WELL TESTING PROJECT MANAGEMENT

Onshore and Offshore Operations

Paul J. Nardone

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Preface

Well test planning is the process of managing the risks associated with well test activity.

A well test induces a dynamic response in a reservoir by producing reservoir fluids to surface. The information acquired, such as, fluid properties, pressure and temperature data, become inputs to a reservoir model to aid in making development decisions.

For the Well Test Planning Team it is the design, installation, and operation of a temporary production facility, to control and produce that response, according to the objectives set by reservoir engineering.

The planning phase can take months compared to the operational phase which might only take weeks, this is where most of the cost occurs. The planning team designs a well test to best achieve the objectives set by reservoir engineering. Along the way they identify issues which require specific well test design features, such as a service, special equipment or a procedure. These features are described in the planning documentation which will later be used to conduct the well test.

The focal point of this planning effort is the Well Test Engineer. The role involves a threefold skill:

Firstly that of coordinator, the Well Test Engineer must understand the processes associated with many specialized services in order to design a well test in which these processes mesh together. Well testing is a service driven activity, oil companies do not perform well tests with in-house expertise and equipment, and neither do oil rigs possess these resources. Instead, third parties, engaged to carry out specific services, perform all of the specialized skills that contribute to the well test. The Well Test Engineer must determine what services are required, prepare contracts and engage the services, and subsequently develop the overall design utilizing those services.

Secondly, that of compliance officer the Well Test Engineer must understand the regulatory processes governing Well Test activities. Government regulations, laws, industry codes, local standards and practices, and company policy all have a bearing on the planning and design. The Well Test Engineer is responsible for ensuring that the Well Test processes comply with all the regulations, part of this requires that the Well Test Engineer prepare much of the documentation, which demonstrates compliance.

Thirdly, that of Well Test Supervisor, the Well Test Engineer plays the lead role during the operational phase of a well test to ensure that the objectives are achieved. The Well Test Engineer prepares the operational

procedure, or Well Test Program, which integrates the well test services and activities to ensure a seamless operation; the Well Test Engineer directs the execution of the program modifies the plan if necessary, liaises with rig management, service contractors, the reservoir engineer, and the company head office.

BACKGROUND

What is the background of the Well Test Engineer? There is no learning institute which issues a qualification for this role, in fact the Well Test Engineer can come from any background, Petroleum Engineering, Drilling, Reservoir Engineering, or from a consulting background, having acquired years of experience working for one of the service companies beforehand. Whatever the background, the role of the Well Test Engineer is as specialized and no less demanding than any of the other disciplines in the oil and gas industry, but some will have more experience than others, which creates the need that this book fills.

STRUCTURE

This book refers as a base case to a well test operation performed on an offshore drilling rig. It is in this environment that the greatest amount of planning is required. However, most of the features and processes described in this book apply equally to well test operations carried out on land. There is detailed discussion on the decision making process, showing how planning teams arrive at decisions utilizing the information available and how they produce the documentation required at each stage in the design process.

The last chapter looks at methods to capture learning's and more importantly at how to apply those learning's. Learning's examine where the operation worked and where it did not by reviewing both the program and the data and samples that made up the product. Equipment performance too makes a good subject for learning's, did it perform as expected and could it have worked more effectively?

Finally a word on units and nomenclature, depending on which part of the world you are working, the reporting units can vary considerably, the traditional unit system in the industry has been based on the American Petroleum Institute (API), which included many imperial units such as barrels, feet, inches and so on. In many parts of the world this system has been replaced using metric units referencing ISO standards with cubic meters in place of barrels, and meters and centimeters in place of feet and inches. Neither system of units is dominant; it varies from country to country and from company to company. Indeed, many companies mix units with lengths measured in metric units of meters, diameters in imperial inches and production rates in API barrels, many report dual units to satisfy company, joint partner and regulatory requirements. A partial explanation may be that some common tubing sizes supplied to the industry incorporate the imperial size as part of the proprietary

reference, i.e. the imperial size is also part of its legal name. In my experience exploration and drilling departments are still more comfortable referring to barrels of oil and standard cubic feet of gas in place of cubic meters.

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Chapter | one

Well Test Planning Environment

CHAPTER CONTENTS

Well test planning is the process whereby resource companies manage the risk associated with well test activity. A well test is a complex undertaking involving a diverse range of contractor personnel, equipment, and services. The well test planning environment is the set of constraints, together with the tools and resources available to the well test engineer and the well test planning team, to carry out planning. Facets of the planning environment may be categorized into decision making, regulatory, local, well specific, and challenging.

1. The preparation time and the experience level within the planning team define the constraints of the decision-making environment.
2. Regulations, contracts, policies, procedures, and financial resources define the regulatory environment.
3. Remoteness, space limitations, and the availability of resources to support the operation define the local environment.
4. Conditions of pressure, temperature, fluid properties, and well depth define the well-specific environment.
5. Challenging environments are defined by exceptional or nonstandard conditions. These include extremes for any of the categories listed above, as well as planning resource limitations and new technologies.

Because each facet of the environment influences the test design in some way, the well test engineer cannot plan a well test without adequate knowledge of that environment. The aim of this chapter is to introduce the various facets of the well test-planning environment that form the background against which detailed planning for the well test takes place. The well test engineer must commit some part of the planning resources in order to acquire the information that defines this environment.

THE DECISION-MAKING ENVIRONMENT

A significant portion of well test planning lies in the decision-making process and embodying those decisions into planning documentation. Each decision carries with it some level of risk in relation to safety, data objectives, or cost. It follows that for decisions entailing significant risk greater planning input is required to arrive at an outcome that satisfies operational needs while minimizing associated risk.

The spectrum of topics for decision making is broad, covering contracts, new technology, equipment specifications, fluids, materials, flow durations, well test objectives, safety barriers, scheduling, manning levels, and so on. The well test engineer cannot reasonably make every major decision in isolation; the risks associated with any single decision may be significant and can carry an operational success or failure consequence. Instead, the planning team collectively reviews the main issues to arrive at a group decision. For the more significant planning issues, for example, packer and fluid selection, the well test engineer collates a number of options, balancing operational advantages and operational risks. These options may derive from contractor input, lessons learned, and the experience of the well test engineer or other team members. The assembled planning team evaluates these options, arriving at a group decision during risk assessments, planning meetings, and program reviews. The appropriateness of each decision is a function of the experience of the planning team and the time given to consideration of the issues surrounding the decision.

In most parts of the world and within most reputable resource companies, regulations and company policy require decisions that involve risk in relation to personnel safety are made the subject of formal assessment following

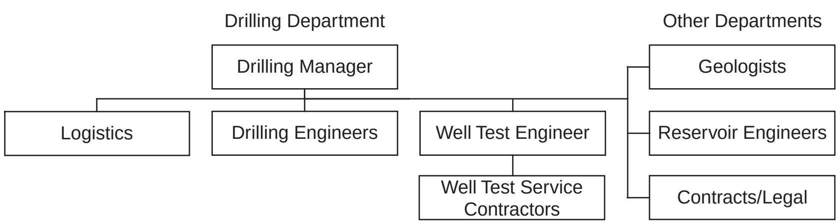


FIGURE 1.1 Typical Well Test Planning Team Structure

established industry standards. Examples of such assessments are Hazard Identification (HAZID) and Hazard and Operability Studies (HAZOP). Decisions pertaining to data objectives and cost may also be subject to formal risk analysis assessments. Many day-to-day decisions that are not documented formally also contribute to planning; such decisions occur at informal meetings between individual members of the planning team, over the phone with contractors, and by individuals responsible for addressing specific planning tasks. Examples include decisions relating to the selection of minor items of equipment and equipment inspection schedules.

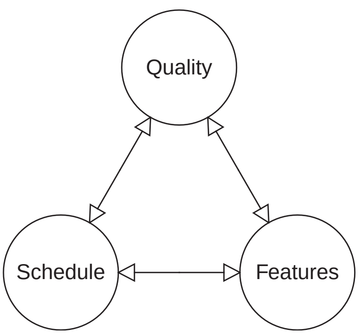
For a well test, measures of quality are the safe outcomes of the test and the completeness and accuracy of the data acquired, including the samples. Features of the test are the well test objectives and the well test services, while the schedule is the time allocated to the planning team in order to conduct planning. Of these three planning elements, it is possible to improve any two but only at the expense of the third. Thus, as features are added to the test and it becomes more complex, the resource company can either sacrifice quality or increase the planning schedule. Given the overarching importance of safety and the value of the data, there are clearly limitations as to the number of features that may be added late in the schedule.

Management of a Rig

For the period that a mobile offshore drilling unit (MODU) is contracted to a resource company, the rig owner and the resource company share its management. The rig owner's representative, if offshore, is the offshore installation manager (OIM), responsible for the overall safety of the rig, its day-to-day management, and the rig crew management. This position is responsible for managing the activity of the toolpushers, drillers, assistant drillers, roughnecks, roustabouts, deck crews, mechanics, catering crew, and so on. Some organizations designate this role as a person in charge (PIC) or the vessel captain.

The resource company representative is the drilling supervisor; this role is responsible for representing the interests of the resource company. The drilling

FIGURE 1.2 Basic Planning Elements



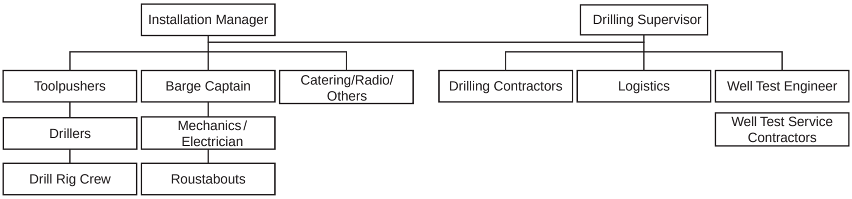


FIGURE 1.3 Offshore Facility Management Structure

supervisor manages the execution of the drilling program and the contractors engaged by the oil company to provide services in support of the drilling program. The well test engineer and the reservoir engineer both report to the drilling supervisor. The drilling supervisor is experienced in the management of a facility and plays a key role in coordinating many of the facility and support resources during the well test.

Critical Path Planning

The greatest cost associated with the well test operation is that of contracting the MODU to drill and conduct the well test. In an offshore environment, this cost is an order of magnitude greater than that of a land-based rig. In today's market, the costs associated with engaging a MODU can vary anywhere up to $1,000,000/day. On a drilling rig, whether land based or offshore based, the primary activity of the rig, drilling, running or pulling completions, logging, or well testing is a critical path activity, so called because these activities add to the rig schedule and so add significantly to the cost for the resource company. Other activities on the rig occur offline; that is to say, they take place simultaneously with the critical path activity of the rig. Offline activities include all those preparations that take place so that the different critical path activities follow one another without unnecessary delays. For example, on completion of a logging operation, the various tools, guns, and test tubing should be ready immediately to pick up and install in preparation for well testing.

In order to manage the cost associated with rig activity, the resource companies place considerable emphasis on planning. In summary, a number of planning objectives derive from the discussion above, first, to ensure that the critical path activity takes place with minimal delay to the rig and second, that the task is performed effectively first time.

Contingency Planning

Thorough planning also provides for contingencies. Every activity on a rig requires equipment, procedures, and personnel for its execution, and each of these can fail to perform to expectations. Many of the planned activities are essential to the well test objectives; the well test engineer must therefore

prepare contingency plans so that critical activities can proceed in the event the original plan fails. On one hand, control cables may snag during installation, downhole tools might fail to operate after repeated operations, valves and pipe seals might develop leaks after prolonged exposure to production conditions. On the other hand, plans might go wrong because of human error and miscommunication, unclear procedures, or fatigue and lack of attention. Contingency plans must consider steps to limit the damage or delay caused by an operational failure. Recovery plans must consider the procedures and equipment required to return the operation to normal status and allow backup equipment to proceed with the operation once recovered from the failure.

Schedule Planning

As each critical path task occurs, in order to minimize cost, equipment and personnel must be on hand so that as little time as possible is lost in the changeover from one operation to the next. The well test engineer has a role to play on site — to communicate regularly with rig management and contractors, so that contractor services are mobilized to the well site in time to allow for adequate preparation. The well test engineer also communicates regularly to the contractors on site during daily planning meetings to ensure that each service is ready as and when needed.

Before mobilization, the well test engineer has a role to play in communicating the overall program schedule to contractors so that they are aware of mobilization timings and can make plans accordingly. Given that the well test is a complex operation involving multiple services and different contractors and suppliers, the challenge to the well test engineer and the planning team is to develop a plan that ensures the smoothest sequence of operations. Integral to this plan is communicating the schedule to every interested party. The schedule needs constant updating because it changes due to delays or modifications to the well program. It is often the smaller contractor or supplier who is omitted from schedule notifications, yet their part may be crucial to the timely conduct of the well test. The schedule should include the information necessary in order for contractors to plan their business. In particular, they need to know when to have equipment and personnel on hand for mobilization to the rig or to some other field location. The current and planned critical path activity directs the timing. The schedule for preparations, mobilization, and offline activity reflects critical path timing. This information is relayed to other members of the planning team, contractors, and suppliers by regularly scheduled updates, weekly at first and daily as the well test operation approaches. A schedule might take the form of an e-mail prepared by the well test engineer and sent to a distribution list, or a more formal approach using a gant chart or a spreadsheet providing details regarding current operations.

Logistics

Exploration activity often takes place in remote areas in order to support their operations resource companies set up support bases close to the rig. For offshore operations, a support facility is usually located at the closest port facility, whereas for onshore rigs the support facility may be located close to the well site. Well test equipment is mobilized from various contractor facilities to the resource company support base for consolidation. Generally, mobilization charges apply as soon as equipment moves from a contractor supply base. If that base happens to be a great distance from the rig support base, the charges for the contractor services will be greater owing to the need to mobilize equipment early so as to reach the support base well before the operation. Sometimes contractor equipment comes from an overseas location, and that equipment is not widely available — for example, high-specification equipment for high pressures and temperatures, or equipment custom built to suit a particular material or dimension requirement, or finally if the drilling activity takes place in a location remote from any contractor facility.

In the offshore environment, getting equipment to a rig requires purposely built supply vessels with large open flat decks that are easily accessible for cranes operating from the rig. Depending on the location of the rig and the support base from where the supply vessels operate, the transit time to the rig may be anything from a few hours to a full day. The number of vessels

FIGURE 1.4 Supply Vessel Delivering Well Test Equipment

supporting the operation is limited, as is the deck space on each vessel; thus, it is necessary to prioritize the equipment loadout according to the operation on the rig. This requires coordination between rig logistics, support base logistics, contractor logistics, and the well test engineer.

The majority of the cargo travels inside purposely built containers and baskets; however, certain items such as the well test separator or steam exchanger are too large to transport inside containers. Specially manufactured protective frames fitted to these units incorporate lifting points to attach lift rigging so that they may be handled in the same manner as other containers.

Lifts that take place to or from floating vessels are subject to dynamic loads. Transport containers, lifting frames, and rigging must be designed to cope with this increased load, which is often referred to as a dynamic amplification factor. This feature of the offshore environment adds significant cost to logistics. Lifted equipment must comply with a comprehensive standard, for example, EN12079 (European Committee for Standardization 2006). In general, these standards are similar and include engineering specifications for the lifted equipment structure, its pad eyes and rigging. These standards also include controls for periodic visual inspections, crack testing, and load testing of lifted equipment and rigging.

Some resource companies have additional requirements that are appended to the local standards. These might include more frequent inspections or particular specifications with regard to the stenciling and identification of individual lifts. Such appendices are usually added when the resource company experiences a lifting-related incident and identifies additional controls through a process of Continuous Improvement.

The task of the company's logistics coordinator is to ensure that all contractors comply with the required lifting standards. The well test engineer can play a role in this process, communicating specific company-lifting standards to well test contractors and coordinating the issue of appropriate supporting documentation.

THE REGULATORY ENVIRONMENT

Regulations are controls that ensure compliance with laws, policies, codes, contracts, and standards imposed by the state and by the stakeholders in the well test. Much of this environment derives from best practice and the learning gleaned from experience. Some of that experience comes from incidents in which loss of life has occurred.

Legal Framework

Governments create laws governing oil and gas extraction within their national and state borders. Interested in the revenue derived from this mineral resource, the government creates some laws to encourage development and to optimize the revenue derived from its exploitation; other laws relate to the

protection of health, safety, and the environment. The government appoints regulators to administer the law through regulations and to audit and monitor the activities in the industry. The degree of regulation varies in parts of the world. Some governments apply strict regulations that often result in severe planning restrictions, for example, some regulations prohibit the flaring of petroleum products during well testing. Others governments encourage self-regulation, recognizing that petroleum exploitation is a complicated activity and that it is in the industry's own best interest to conduct its business in accordance with best practices.

On land, mineral rights sometimes belong to the landowner, who then sells the right to exploit the mineral to developers; otherwise the mineral rights belong to the state, although the landowner is usually entitled to compensation for the disruption resulting from its extraction. At sea, the situation is simpler because no one owns the sea surface. Government owns the mineral rights below it, at least out to about three miles, the coastal sea. This distance may vary according to water depth and internationally agreed-upon boundaries. Beyond that, international convention controls exploitation of mineral rights on the continental shelf. The exploitation depth depends only on how deep technology can go to extract the minerals. Beyond the continental shelf, different rules apply, but exploitability is limited (or nonexistent); therefore rights issues do not arise. Some countries have very narrow shelves, for example, the California coastline deepens precipitously out beyond six miles, whereas the United Kingdom has one coastline that extends into the North Sea, although it shares those rights with other countries around the edges.

Mineral rights become legally tangled when a specific reservoir structure spans more than one area licensed to different resource companies. Production from the reservoir in one license may deplete reserves in another. Much depends on the interpretation of field modeling, which in turn also depends on the data input to the modeling, some of which derives from well testing. The term sometimes used to describe this form of reservoir definition is *field unitization*.

Whatever the complications, the resource company has a responsibility to comply with regulations in order to obtain approval to test. The most stringent aspect of the regulations generally relates to safety and the environment. Resource companies must demonstrate that their planning adheres to the requirements under these regulations, after which the resource company must demonstrate that the objectives and the planning in place, including the program, are adequate for further development of the resource.

Regulators

A regulator is a government body assigned to administer governmental acts or laws. In the case of the petroleum industry, a specific government body, and in some instances more than one such body, administers laws in relation to

petroleum exploitation. For example, a single body or department might oversee legal compliance in matters of safety within the industry and might be assigned to manage permit licenses and petroleum development or exploitation. In some instances, these bodies divide along federal and state lines, depending on the location and nature of the activity. In the UK the Health and Safety Executive (HSE), as the name of the agency states, administers matters relating to health and safety. In the United States the primary authority is the Minerals Management Service (MMS); in Norway, the government regulator is the Norwegian Petroleum Directorate, while in Australia the National Offshore Petroleum Safety Authority (NOPSA) administers health and safety regulations.

Regulations

Regulations are the rules issued by a government regulator to interpret and apply the law. They are intended to help resource companies achieve compliance. In effect, regulations are controls to help resource companies achieve compliance with the standard, in this case the law.

Historically, up to the mid-1980s and in some parts of the world today, safety regulations applied to the oil and gas industry have been prescriptive, with heavy focus on safety equipment standards and specifications. A weakness in this method of safety regulation is its lack of focus on the human interface, that is, the management systems and methods of operation. In addition, a prescriptive regime is slow to respond to changes introduced by new technologies and practices.

Subsequent to the *Piper Alpha* disaster in 1988, which resulted in the loss of 167 lives, a significant change came about in the approach to safety regulations with the introduction of the Safety Case regime. The Safety Case moved away from an exclusively prescriptive environment to one in which resource companies and rig owners were required to demonstrate a comprehensive approach to safety management for their operations.

The interaction between the regulator and the company is an important feature of well test planning. The regulator issues the approvals necessary in order for well test activity to proceed. To obtain the necessary approvals, the company must demonstrate to the regulator that well test planning complies with the regulations and therefore with the relevant laws.

The process of demonstrating compliance and obtaining approvals in relation to the well test is one of the tasks of the well test engineer and is described in this book. In particular, Chapter 6 describes a process that helps the well test planner achieve compliance within a Safety Case environment. Although not adopted everywhere, the Safety Case is generally recognized as the leading approach to the management of safety in the offshore oil and gas industry.

Approvals

The approvals required to proceed with a well test vary in different parts of the world, but typically they apply to specific activities. For example, approvals may be required for a safety case and a Well Test Program separately. The issue of an approval is based on an application that is supported by evidence provided by the resource company demonstrating compliance with the regulations in relation to the particular activity. For example, if the resource company intends to flare hydrocarbons, the planning documents must demonstrate that all regulations in respect of flaring, if any, have been addressed.

Notifications and Reporting

The interaction between government authorities and resource companies during well drilling and well test activity depends on the nature of the task or issue. For example, a petroleum resource development regulator requires that well data reports assess the merit of a resource company approach to field exploration and development. Other authorities, such as the Coast Guard or Maritime Safety authority, and the environmental protection authority all have interests in the resource company activity and may have reporting requirements — for example, medical evacuations, fires, flaring notifications, and oil spills. The management processes put in place by the resource company to control these hazards must also include processes to ensure adequate reporting to government authorities.

Company Policy

Company policies are self-imposed regulations that govern how a company goes about its business. The highest levels of management set company policy. Management systems, company standards, and practices are some of the controls used to implement policy; these tools provide guidance to company employees and help the company to manage business risk. Policy provides high-level guidance on a range of matters. For example, many companies use policy to define safety and environmental priorities over financial considerations, or to define policy on drugs and alcohol. Management systems and practices are developed based around company policy; examples include risk management tools, the use of safety equipment, engineering practices, and financial and contracting practices. Policies and practices that may directly influence well test planning include practices in relation to well barriers, test fluids, tubing design, and pressure testing.

A challenge for many resource companies, particularly larger organizations, is to strike a balance between appropriate administrative controls that ensure compliance with company policy and excessive documentation. Some controls require greater effort for the process of demonstrating compliance than achieving compliance.

Standards

The purpose of a standard is to ensure that a process. As well as the product that is the output of a process, is fault free and capable of performing its intended purpose. Although adherence to standards is not always mandatory, company policy, good practice, and good business sense promote the use of appropriate standards in well test planning. Compliance with specific standards becomes mandatory if it is stipulated in a contract between the resource company and a contractor or if stipulated in regulations. Standards take many different forms — often a detailed set of procedures governing equipment manufacture or process analysis. Some prominent and widely recognized industry standards referenced for well testing are as follows; others are referenced throughout this book and in the appendices as the need arises.

API Specification 6A, Specification for Wellhead and Christmas Tree Equipment

API Specification 5CT, Specification for Casing and Tubing

API Specification 12K, Specification for Indirect-Type Oil Field Heaters

API Specification 12F, Specification for Shop Welded Tanks for Storage of Production Liquids

ANSI/API Specification 14A/ISO 10432, Specification for Subsurface Safety Valve Equipment

ANSI/API Standard 521/ISO 23251, Guide for Pressure-Relieving and Depressuring Systems

API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms

ANSI/API RP 14 E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems

ANSI/API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, and Zone 2

API RP 520, Recommended Practice 520: Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries-Part II, Installation

NACE Standard MR-01-75

ASME section VIII for pressure vessels

ASME B31.3 for pipework manufacturing

Standards are essential to any quality plan, but referencing a set of standards does not guarantee their implementation. When analyzing operational failures for Continuous Improvement purposes, failure to implement standards is often identified as a causal factor. Controls are essential to ensure that standards are implemented. However, controls themselves are not always effective and often depend on the attitude and support of management; management attitude is in itself a control. This never-ending effort to maintain effective controls, and therefore standards, requires a great deal of management commitment.

FIT FOR PURPOSE

A fit-for-purpose product is one that will reliably perform the task for which it is intended. The term *fit for purpose* encapsulates the intent behind the application of any standard or set of standards. Use of this term implies that the standards that pertain to a particular product or process have been applied.

BEST PRACTICE

A best practice is a company-specific standard applied to a process that has been proven through experience to provide successful outcomes. Best practices evolve with the application of a Continuous Improvement process and may relate to any aspect of planning and execution, including company policy, management systems, company standards, safety and the environment, contracts, invoicing, document control, design and engineering, and contractor and personnel management.

CONTRACTS

A contract is a legally binding document that details the technical and financial commitments between the resource company and the contractor. Well testing is an activity conducted almost entirely by third-party contractors specializing in one or more of several well test services; each provides equipment and personnel with the skills necessary to perform the tasks that form part of the service. For example, the drilling rig is itself owned and operated by a contractor engaged by the resource company; the rig owner provides the crew and the rig, that is, the drilling facility. The arrangements between the resource company and each of its contractors are detailed in a contract between the two.

Standards apply to the contracts process, just as they do with any other planning or operational process. In this context, standards help to manage financial risk in addition to HSE and operational risks. For this reason, the application of standards within the contracts process must be applied as rigorously as to any other planning or operational process.

IN CONTRACTS

- How do standards control financial risk?

In the contract between the resource company and any third-party contractor, various areas of the contract identify financially binding commitments — for example, a price list for equipment and services and a set of terms and conditions that are a legally binding set of rules, or controls, that reduce the financial risk for the resource company. For instance, terms and conditions often include rules governing the content of invoices such as contract and Approval for Further Expenditure AFE references, and minimum required supporting documentation.

- How do standards control HSE risk?

In order to achieve eligibility to bid for contract work, resource companies stipulate minimum HSE standards that contractors must satisfy. Resource companies use a prequalification process comprising safety management systems audits, together with evaluation of contractor HSE statistics in order to assess HSE risk in relation to a particular contractor.

- How do standards control operational risk?

In addition to financial and HSE standards, contracts also identify technical standards in relation to manufacturing, management systems. including maintenance and specifications, and to operating procedures. Adherence to these standards is legally binding once both parties have accepted the contract.

The contracts procedures and standards evolve through a Continuous Improvement process, resulting in additional terms and conditions or changes to the contract structure or tendering process based on the experience gained from previous contracts.

CODES

A code is a standard, or set of standards, for which compliance is a legal requirement.

QUALITY

Quality is a goal and depending on the feature of the well test, achievement of this goal is measured using different criteria. An organization might assess the feature of safety according to the criteria that no safety incidents occurred during the operation. Operationally, quality might be measured by the criteria that all data objectives had been achieved. Financially, a quality outcome might be measured according to the criteria that the well test is completed on time and on budget.

Quality and standards are intimately related: a quality outcome is the object of a standard. However, it is one thing to have a standard, but it is something else to achieve it. For this reason resource companies develop quality assurance processes that include controls that help to achieve standards compliance. Controls can be as diverse as the range of operations they govern; they might include audits, inspections, supervisor witness, and sign-off on critical operations such as pressure testing, documented procedures, permits, toolbox meetings, and operational procedures. The regulations governing well test activity are themselves controls applied to ensure compliance with the law. At an operational level, controls exist to ensure quality in day-to-day operations. For example, a valve status control board is a tool that is often utilized to track and manage the multiple valve operations just prior to the well test. Checklists are frequently included in the program to control the level of preparation for different activities.

Standards Bodies

The oil and gas industry in most parts of the world is largely a self-regulated industry. Governments set laws and regulations, but thereafter the industry generates the standards governing equipment and processes. In relation to well testing, there are numerous standards. Some relate to the fabrication of well test components such as pipework, pressure vessels, and valves, whereas others relate to lifting equipment, installation of test equipment, materials, electrical equipment, and the management of hydrogen sulphide. The many standards applicable in the industry were generated by various industry bodies in different countries. Most locations reference the same standards or standards that are similar to, and interchangeable with, international standards. Some well-recognized industry standards bodies include

International Standards Organization (ISO)
American Petroleum Institute (API)
Norsk Sokkels (NORSOK)
UK Offshore Operators Association (UKOOA)
NACE International (formerly National Association of Corrosion Engineers)
American Society of Mechanical Engineers (ASME)
American National Standards Institute (ANSI)
American Society of Tube Manufacturers (ASTM)

Class Societies

A class society is a body that assesses the application of different standards using processes that themselves are standards. These societies originated historically within the shipping industry to ensure that ships and other vessels conformed to internationally agreed regulations. Although they still perform this function; their role has expanded so that they are used in a number of industries, from manufacturing to the oil and gas industry.

Examples of some of the most well-known class societies include

Lloyds
Det Norsk Veritas (DNV)
Bureau Veritas (BV)
American Bureau of Shipping (ABS)

Regulations and Safety

Many activities in the oil and gas industry are hazardous by nature. At any given well site, daily activities include work with cranes, work at heights, pressure, moving parts, and work with hazardous materials — all of this in a relatively confined area and often simultaneously.

Facility owners and resource companies operate safety management systems that provide tools to control the hazards associated with their job activities. A permit to work system and the DuPont Safety Training Observation

Program STOP are two such tools often found in a safety management system. Most companies also precede each activity with a review of the procedure and the hazards associated with the activity. These reviews, sometimes called toolbox talks or Job Safety Analysis (JSA) talks, involve the participation of crewmembers doing the job.

For an activity such as well testing, which involves the introduction of special process equipment and the containment of hydrocarbons under pressure, a more comprehensive approach to safety management is required.

A risk management plan or a Safety Case specific to the well test incorporates a comprehensive description of the well test facility and a detailed assessment of the hazards associated with the well test activity. This approach to the management of well test safety is required by regulation in many parts of the world and by many resource company policies and practices. Chapter 6 describes in detail the features and processes involved in the management of safety during a well test and the preparation of a well test risk management plan or safety case.

Role of the Well Test Engineer

In relation to the regulatory environment, the role of the well test engineer is to demonstrate compliance. This is achieved through the well test planning documentation, including safety case submissions and programs.

THE LOCAL ENVIRONMENT

The local environment is the set of physical features unique to the location of the well test. It examines how the nature of a location, its remoteness and the resources available to support the operation, play a role in defining the well test environment.

Language and Culture

The challenges attached to working in different countries go beyond the obvious barriers posed by language. In many parts of the world, cultural behaviors can be difficult to integrate into those required in an oilfield environment. Resource companies commit to developing a working culture in relation to quality and safety. Operating in remote parts of the world and employing large numbers of personnel from the local workforce, resource companies face challenges to promote and maintain a culture in line with the company vision. Resource companies cannot simply import the entire labor force, although many specialists often travel internationally to different well sites. Regulations in many countries impose work restrictions on visitors from overseas so that resource companies must set up work arrangements with local authorities to ensure that specialized personnel can enter the country to carry out specialized work. Resource companies must often commit significant resources to additional training in order to promote safe

working behaviors in remote locations. For the well test engineer, it is necessary to understand the way in which these cultural differences might affect the conduct of the well test. As already mentioned, well testing is an activity largely performed by third-party contractors utilizing personnel from varied cultural backgrounds. The author has observed instances in which these cultural differences have resulted in operational problems, frequently stemming from miscommunication. There is no easy solution to this problem, for the resource company must invest a great deal of training and commitment to reeducate a workforce into an appropriate company culture. An experienced well test engineer will have adequate communication skills to recognize the capabilities of the personnel provided in the contractor crews. In order to promote better communication between different contractors, additional preparation time must be factored into well-site operations to allow time for crews to become familiar with one another and to start working as a team.

Green Testing

Well test activity can take place almost anywhere — offshore near shipping lanes, or close to marine parks, whale migration paths, fishing grounds, or beaches and cities. While on land, well testing may occur near population centers, parks, forests, farms, or other areas of particular sensitivity. Any well test activity that has the potential to affect the surrounding environment requires assessment to identify controls that will minimize the potential for damage arising from that activity. Potentially harmful activities include flaring of hydrocarbons, oil transfer operations, and the use of special chemicals in the well test process, in particular, well tests associated with the production of hydrogen sulphide, which is highly toxic. Indirectly, heat radiation, noise, and the activities of the services that support the rig may also contribute to overall environmental impact. For example, heavy vehicles accessing areas with poor roads can cause damage to the local infrastructure. This affects the lives of the local community dependent on that infrastructure.

Resource companies develop environmental plans at the outset of their operations that identify areas where the operation has the greatest potential for adverse environmental effects. Environmental plans also detail the controls that need to be in place to minimize the potential for environmental damage and the mitigation and contingency measures in place should an incident occur. Environmental management plans are a legislative requirement in many parts of the world and are required as a matter of policy within many resource company organizations.

The well test engineer does not routinely prepare environmental plans because these also cover other activities such as drilling; support facilities, and supply vessels. However, in cases where significant risks are associated with well testing due to the nature of the well test or sensitivity of its location, then the well test engineer has a role to play. For example, the

environmental plan may impose restrictions on flaring that can impact the design of the well test.

Physical Location

Onshore locations range from deserts and farms to mountainous, heavily populated, and arctic regions. Offshore locations range from cyclone (hurricane) and deepwater regions to fishing grounds, marine parks, whale migration routes, and shipping lanes. The range of challenges working in each of these locations is equally diverse. In the following descriptions comparing land-based locations to offshore locations, I have kept the discussion general with occasional reference to specific well test issues. The aim is to provide the reader with a description of the locations against which detailed well test planning takes place.

Onshore

In developed countries, the communication network and general infrastructure are usually adequate to support operations anywhere well tests might occur. Challenges to the planning team are primarily engineering challenges and relate to well test design. During periods when demand for well test services is high, the availability of equipment and personnel becomes a planning challenge. Unlike offshore operations however, there is no subsea service, and the equipment required does not mandate the use of expensive offshore lifting frames. Frequently, though not necessarily always, onshore well conditions are less extreme than those found offshore. As a consequence, the equipment specification for land-based well tests may be different than for offshore. The regulatory environment in developed countries is generally more rigorous. Land operations close to population centers or in environmentally sensitive areas may require special measures such as restrictions on flaring, restrictions as to the duration of the well test, and restrictions as to the time of year when testing is permitted to take place.

Planning issues are more numerous for well tests in less developed and remote areas. The nearest well test service support might be some hundreds or thousands of kilometers away, possibly across international borders and overseas. Early planning decisions are required to secure the services and equipment to allow sufficient time to mobilize the equipment and to set it up in time for the test. Although the local authorities might be less demanding with regard to regulatory and environmental compliance, the majority of responsible resource companies apply self-regulation not unlike that which might apply in a developed country. There are several good reasons for doing so: to protect employees, to preserve one's reputation, to maintain positive relations with local communities, and to comply with company policy.

In remote mountainous terrain such as that found in the highlands of Papua New Guinea, helicopters are sometimes the only means available to transport

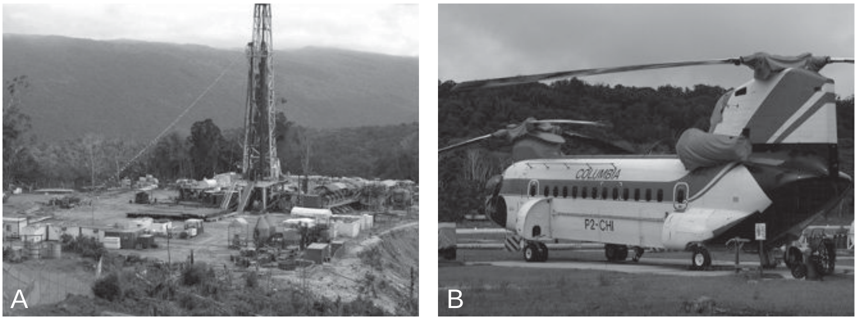


FIGURE 1.5 (a) Remote Highlands Wellsite (b) Cargo Helicopter

equipment to a rig site. This adds cost to the operation since almost all supplies, material, and personnel must travel by air. Sometimes specially adapted lifting frames are necessary so that equipment can undersling beneath a helicopter. Still more exotic is the transport means of getting supplies to arctic regions using hovercraft or hover barges towed by helicopter.

LAND-BASED RIGS

Land-based rigs are modular so that the components that make up the rig are small enough to transport by road. Each module is mounted inside transport skids or containers suitable to transport on truck flatbeds. Trucks bring the modules to a prepared well site, which is a flat, open area large enough to accommodate the rig modules for assembly. In many instances, the roads to the well site are expressly built beforehand to provide truck access. In areas prone to heavy rain, additional ground preparation may be required to facilitate vehicle movement and the installation of the rig structure. In addition to this measure, rig sites require continuous maintenance using graders to level the ground periodically as it degrades with use by heavy vehicles and bad weather. Other preparations include the digging and lining of pits, to store drilling fluids. The modules comprising the drilling rig structure including the derrick, draw works, Blow Out Preventer BOP, and catwalk, while the pump skids, pipe racks, and accommodation modules are located around the main rig.

If a well test forms part of the well program, a special area is set aside to locate the well test gear, and a dedicated flare pit is prepared away from the accommodation.

Offshore

The conditions of the sea environment in which an offshore facility operates are often termed the *metocean conditions*. The term *metocean* derives from a combination of the words "meteorological" and "oceanic." Metocean conditions include the water depth, tidal data, heave and wave conditions, and seasonal weather information. Because the cost of operating an offshore rig is

significant, interruptions caused by extremes in metocean conditions can be very costly. These interruptions affect logistics in particular, since helicopters, cranes, and supply vessels cannot operate safely in severe weather conditions. Resource companies endeavor (not always successfully) to coordinate their offshore drilling operations to coincide with the optimum metocean seasonal windows, in particular areas such as the Gulf of Mexico, the Timor Sea, and others where seasonal cyclones (hurricanes) necessitate the evacuation of rigs. Planning an offshore operation includes the development of response plans for a range of hazards, not just those posed by metocean conditions, but also those due to loss of well control, fire, and ship collisions. In an offshore environment, personnel cannot simply walk away from a hazardous situation. Evacuation plans are required to ensure that the resources necessary to remove personnel from the rig are available when they are required. For example, helicopters and personnel transfer vessels need to be on hand for the duration of the program.

Well test equipment interfaces more intimately with an offshore facility compared to a land rig, for reasons having to do with the restricted availability of space and the need to interface rig safety equipment, in particular the rig BOP. One consequence of the additional interfaces is the need for an additional well test service, not found on land rigs — the subsea service described later in the chapter on well test services.

WATER DEPTH

More than any other metocean variable, water depth most influences the type of facility selected to drill the well. As the water depth increases, the options available regarding the vessel from which to drill the well decrease. In deep water over about 600 m (2000 ft), few vessels are capable of mooring to the seabed. The remaining option, to utilize a dynamically positioned vessel, adds significantly to the cost of the operation since these vessels are also few in number and command high contract charges. They also consume a considerable quantity of fuel due to the need to remain on station with thrusters that are in constant use throughout the drilling program.

The interfaces between a floating drilling vessel, the ocean, and the wellhead on the seabed entail specialized equipment and procedures. The design of these interfaces facilitates the primary function of the rig as a drilling unit. When it comes to a well test, certain new interfaces appear, which require additional equipment and additional procedures — for example, the type of subsea valves that interface with the BOPs, the securing of the control umbilical to the tubing, and the procedures for managing the fluid in the riser.

In deep water, additional well test challenges appear, owing also to the cooling effect of the ocean and to hydrostatic forces in the riser. These issues are discussed in later chapters of this book.

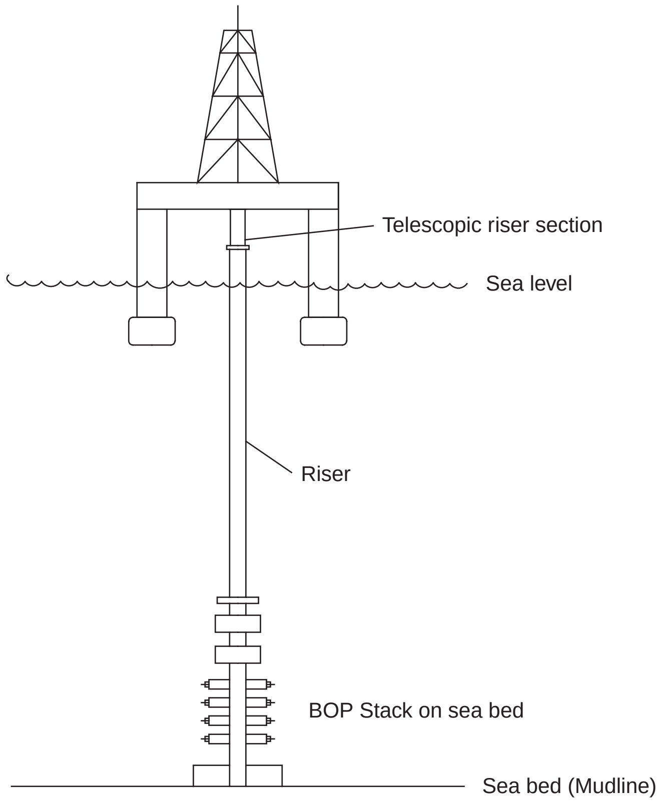


FIGURE 1.6 Offshore Interfaces

WEATHER

Many of the activities on offshore vessels are limited to varying degrees by weather. Handling pipe in the derrick can be hazardous if the vessel is rolling severely. Similarly, moving pipe or other equipment about on deck is also hazardous, presenting risk of injury to personnel and damage to equipment as a load, suspended like a pendulum from the crane jib, swings with the roll of the vessel. Along with rolling seas and high winds, excessive heave presents limits during drilling and other operations, which require that the rig compensators control the loads on the work string. Apart from the activities of the drilling vessel, the weather can also restrict the activities of vessels supporting the operation. These vessels deliver equipment, fuel, water, drilling fluids, food, and other essential supplies needed to maintain the activities of the drilling vessel. Helicopter activity transporting personnel and freight to and from the vessel also shut down in severe weather conditions. At the approach of extreme weather such as a cyclone (hurricane), which may pose a threat to the safety of the vessel, partial or complete evacuation of all personnel may be required. Delays caused by severe weather conditions add

significant cost to the operation. Some resource companies attempt to reduce this cost by attempting to schedule operations during periods of less severe weather activity.

FLOATING OFFSHORE RIGS

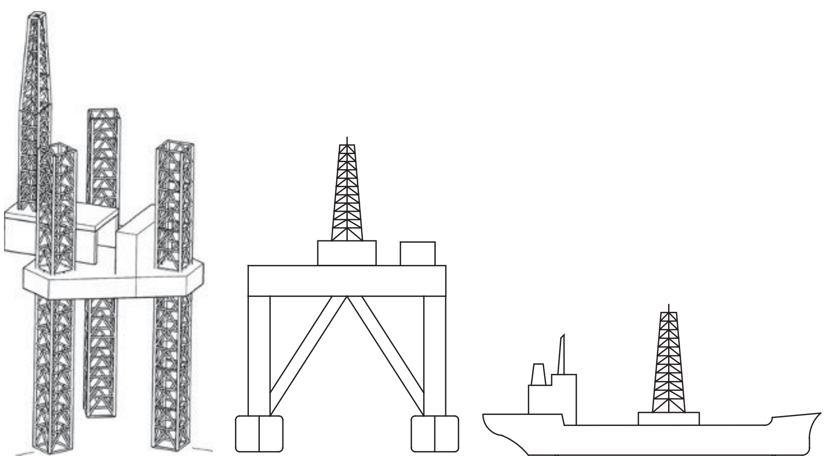
Floating offshore rigs or mobile offshore drilling units (MODUs) come in different shapes and sizes; no two are ever the same. A MODU incorporates many of the systems of a ship and combines them with those of a drilling rig. Like a ship, it has a ballast system, engines to generate power, anchors for mooring, accommodation for personnel, and radar and radio communication for navigation. However, the primary function of a MODU is drilling, and for this purpose it requires all of the systems associated with drilling activity — a drill rig with a derrick, draw-works for running pipe and drilling, pits, shale shakers and pumps for fluid storage and handling, pipe decks for handling casing, drill pipe and tubing, and BOPs for subsea well control. Unlike a ship which spends much of its working life moving between ports gathering and delivering cargo, a MODU spends much of its working life stationary over a well. Its propulsion system if any (for many MODUs are towed to site) is disengaged; instead. its generators deliver power to drive the various systems on board. Because it is stationary for long periods at sea, personnel cannot simply change out when it arrives in port. Most MODUs are fitted with helidecks to permit change out of personnel via helicopter. Other crewmembers change using personnel boats. The different systems and the unique application of its ship-like systems result in a facility that has a unique management and crew structure.

There are two general classes of MODU: semi-submersibles and drill ships. A semi-submersible is a platform that stands on pontoons submerged just below the water surface. Semi-submersibles provide a stable work platform with the drilling rig located at the centre of the platform surrounded by a large open deck for storing and preparing equipment in support of the operation. Drill ships are single-hull vessels similar to ships; indeed. many are converted ships, with a drilling rig positioned amidships, and the deck space fore and aft utilized for storage and preparation. Drill ships lack the stability of semi-submersibles and tend to be more space restricted.

During operation, whether drilling, completions, or well testing, a floating MODU must maintain a constant position above the well. It can achieve this in two ways: with a mooring system or with dynamic positioning. A moored vessel uses anchors extending in a pattern around the MODU, each anchor automatically tensioned so that there is relatively little movement of the rig from its station above the well. A dynamically positioned vessel uses thrusters to counter the effect of wind and currents, which tend to push the vessel off location. The thrusters are computer controlled, transponders located on the seabed provide signals to the vessel that allow the computer to determine its position in relation to the transponders at all times and automatically apply thrust to maintain position.

There is a third class of MODU, which is not floating, at least while it is drilling. This class of MODU is the jack-up. Jack-ups combine the features of a barge and a platform. Once towed on location above the well position, jacking legs, either three or four depending on the design, extend below the platform down to the seabed. At this point, as the jacking motors still attempt to drive the legs down, the barge or platform starts to rise up on the legs. Once clear of the water and at a designated working height, the drilling rig extends off the end of the platform on a cantilever and the jack-up can begin drilling operations. Although this type of facility is very stable, given the nature of the design, it is limited to work in water depths of only around 100 m. Some large jack-ups are capable of working in water depths of around 150 m.

The family of semi-submersibles, drill ships, and jack-ups together make up the majority of facilities used offshore to drill and well test. Apart from these, well tests may also occur on barges, which are useful for working in shallow, swampy areas such as river estuaries, and production platforms and floating offshore production facilities, which occasionally need to test existing production wells. Most production facilities incorporate well test facilities in their design. The production team, in order to determine well contribution to overall field production and to gather other well-specific data for monitoring and field production optimization purposes, routinely carry out well tests. (I have not included any further discussion on well testing from production facilities in this book since input from the well test engineer is not normally required in this type of environment.)



A B C

FIGURE 1.7 (a) Jack Up (b) Semi Submersible (c) Drill Ship

THE WELL ENVIRONMENT

The well is a conduit between the rig and the reservoir. The well environment is specific to the reservoir in which the well test will take place.

Pressure

The ability to control pressure will be a recurring theme that emerges in many planning issue guises — for example, the barrier philosophy, equipment specifications, tubing stress analysis, and fluid selection.

Pressure is stored energy; understanding and controlling that energy features prominently in planning. Uncontrolled pressure represents risk, including risk to personnel safety and risk of damage to equipment, facilities, and the environment. The consequences depend on the nature of the fluid under pressure whether liquid or gas, flammable or toxic. The consequences are also influenced by how and where an uncontrolled release takes place, whether inside the wellbore or at the surface facility. This in turn depends on the source of the pressure, the reservoir representing only one source; other sources include pressure due to the hydrostatic effects of introduced fluids and pressure applied by pumps or stored in pressure vessels. Much of the knowledge detailed in the many standards used in the oilfield addresses the various controls needed to manage pressure. These controls include specifications for equipment required to contain pressure, safety devices designed to protect personnel and equipment, materials designed to work in different pressure environments, and the procedures required to apply these various controls.

Pressure is measured in various units. The common metric unit is the Pascal (Pa). Since one atmosphere is 101325 Pascals, a more practical way to express this unit is the Mega Pascal (MPa), which represents 1×10^6 Pa. The traditional oilfield unit of pounds per square inch (psi) is still widely used in many parts of the world.

Temperature

The temperature in the reservoir, and consequently the temperature of the fluids pumped into or produced from the well, have a significant bearing on the overall well design and later on the well test design. Materials behave differently at extremes of temperature. For example, metals, including casing, tubing, tools, and other equipment, expand or contract, sometimes producing significant movement and/or forces that push equipment to extremes, while elastomers used in seals downhole and on the facility behave differently, according to the temperature, which sometimes affects their ability to seal and contain pressure. In addition to its effect on metals and elastomers, temperature also acts on the various fluids in the well environment. Fluids expanding as temperature increases generate increased pressure.

By contrast, cold fluids cause contraction, resulting in a reduction in fluid volumes. Like pressure, temperature is an important consideration in equipment and material specifications and influences many design issues, as will be seen.

Well Design

The well design consists of those features of the well environment that make up the conduit between drilling rig and the reservoir. A subsurface department comprising geologists and reservoir engineers set well objectives based upon geology, seismic, and offset data. Well objectives should not be confused with well test objectives. Well objectives identify drilling objectives such as well depth, hole size, and direction and might also identify a high-level objective to perform a well test. Well objectives direct much of the well design, since, in order to achieve those objectives, drilling must pass through geological structures that overlay the formation targets. These structures provide drilling hazards in the form of shallow gas, unconsolidated sand, loss of circulation or overpressure zones, and sections of hard impervious rock. The drilling team constructs a well design to achieve the well objectives, taking into account the various drilling hazards. The well design incorporates casing design, drilling fluids, bit and tool selection, and drilling technique to manage drilling hazards.

When the subsurface team adds a well test to the well objectives, additional demands are placed on the well design since the well test may require specific features such as a cemented liner across the target formations to provide wellbore stability and a well barrier during the test string installation. Some design features are mandated by company policy. For example, many companies stipulate the use of brine as a well test fluid. Other well test features influencing well design include additional rat-hole for gun release and logging purposes and higher casing test pressures to accommodate annulus pressure control of well test tools.

The well design is an input to the well test design. The information provided drives much of the equipment selection. For example; the size, and sometimes the type, of packer is limited based on the casing or liner size, and the quantity of tubing required for the test is a function of the measured depth of the well.

OPEN OR CASED HOLE?

An open hole well test is one that takes place in a well with an uncased formation. The production casing stops above the reservoir formation upon completion of drilling the final section of hole through the formation, it remains only to scrape the casing in preparation for setting a packer and to condition or change the well fluid.

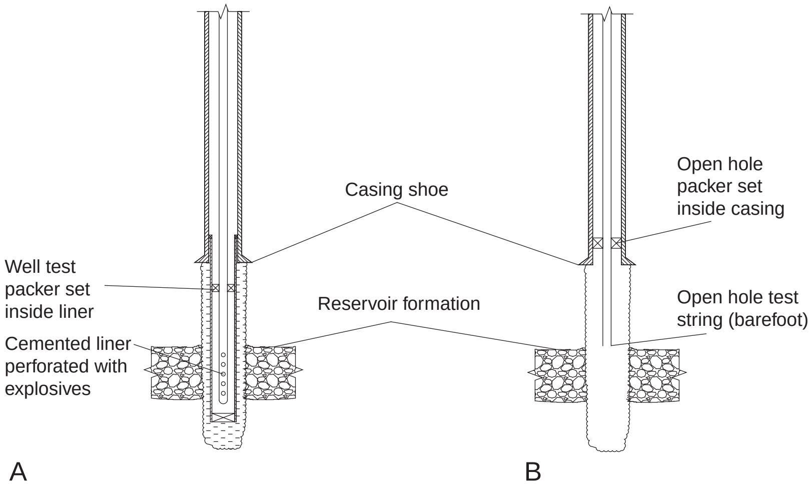


FIGURE 1.8 Cased Hole & Open Hole Well Design

This aspect of the well design has significant consequences for the design of the well test, with a risk that the wellbore may deteriorate and even collapse prior to or during the well test. The primary reason for running a liner is to maintain borehole stability, reduce fluid losses to the formation, and provide a barrier during the installation of the test string. Setting and cementing a liner across the final hole section is an expensive addition to the well design. Apart from the liner consumables and the significant critical path installation cost, a cased-hole well test requires the services of an additional contractor to provide perforating services. For an exploration well, installation of a cemented liner occurs only in the event a well test takes place. Confirmation of a well test is normally based on wireline logs, which are run as part of the drilling program. Once the decision to test has been made, only then is the decision made to run and cement the liner. In order to omit this step and to conduct the test open hole, the subsurface team should be confident that there is no possibility that the hole condition will deteriorate in the time it takes to prepare and install the test string. This process may take anything from 24 to 48 hours depending on the well. The cost of recovering from a situation where the wellbore had collapsed would be considerable. In the offshore environment, given the operating costs and the potential risks, it is a best practice within most resource company organizations to run a cemented liner in preparation for well testing.

BARRIER PHILOSOPHY

When a resource company defines a barrier philosophy for a well, it is defining the number of barriers that the design should include between the reservoir

and the facility at any given time. The barrier philosophy will also include a definition as to what constitutes an acceptable barrier. There may be a number of restrictions; for example, the barrier may have to be proven, that is, pressure-tested, to verify that it can safely contain pressure. Examples of well barriers include the following:

- A facility BOP pressure-tested at regular intervals to confirm its ability to contain maximum well pressure.
- A cemented casing, which has been pressure-tested.
- Continuously monitored kill weight fluid.
- A tested packer (annulus barrier only).
- A tested valve (tubing only).

The barriers in place during drilling operations may not be in place, or valid barriers for the well test, for example, the fluid in the test string once displaced to underbalance fluid is no longer capable of containing reservoir pressure and is therefore no longer a barrier. Once perforated by TCP guns, the cemented liner is no longer a valid barrier.

The BOP is a barrier, which can operate continuously on the annulus when the rams are closed. However, in order for the BOP to act as a barrier on the tubing, it must be capable of cutting the tubing and closing to form a seal. This is not a very practical barrier to rely on; therefore, in order to maintain consistency with the barrier philosophy, without the need for drastic measures such as planning to shear the test tubing, the well test design incorporates barriers integral to the test string, which can be operated independently of the rig BOPs. Examples of test string barriers include the downhole tester valve and the Subsea test tree.

The barrier philosophy may also stipulate that the minimum number of barriers must be capable of maintaining pressure integrity when the rig is absent. For example, on offshore operations if the rig were to move off location due to an approaching severe weather system, then it must be capable of disconnecting at the seabed in a manner that leaves the well secure. The downhole tester valve and the subsea test tree fulfill this requirement. The interface between an offshore MODU and the subsea system is discussed in later chapters.

Well Depth

When referring to well depth, it is important to specify a reference point and to determine whether depth is measured depth (MD) along the well or true vertical depth (TVD). If a well is deviated, the difference between MD and TVD can be significant. MD can easily reach twice that of TVD. Both have consequences for the design of the test. On one hand, measured depth influences the amount of equipment needed to reach the bottom, that is, the number of joints of tubing and the fluid volumes required to fill both the annulus

and the tubing. TVD, on the other hand, is the only measurement relevant for calculating hydrostatic pressures. A depth reference is a point from which all depths are measured. The reference can be almost any common point on the facility — for example, the rotary table or a physical feature external to the facility such as the mean sea level (MSL), the lowest astronomical tide (LAT), or subsea depth (SS).

The well depth has consequences for almost every aspect of the well test. A greater depth means higher pressures and temperatures; this increases the stresses on the test string and influences the type of equipment run with the test string, such as the packer. There may be additional consequences arising from the equipment selected — for example, running a high specification packer such as a permanent seal bore packer. This type of packer is normally set on wireline prior to installation of the test string, given a greater depth. It is possible that even the weight of the wire could become sufficient as to necessitate running the packer on tubing or drill pipe, turning a 6-hour operation into a 24-hour operation.

With increasing depth, the volumes of fluid required are greater. As the TVD increases, so too does the hydrostatic pressure at the bottom of the well. Valve operating pressures, fluid stability, and circulating times are also increased. In deeper, hotter wells, water-based and oil-based drilling muds become unstable, which can affect tool operation. Often, this necessitates the use of brine as a test fluid, even if the operation to displace the well fluids to brine adds further to the preparation time for the well test.

THE CHALLENGING ENVIRONMENT

Definition

Effective well test planning should account for all variables. The first intuitive pass at a list of factors that contribute to a challenging environment might include high pressure and temperature, deep water, high production rates, heavy oil, high levels of hydrogen sulphide, carbon dioxide, paraffin wax, foam, and hydrates. Market conditions also demand more accountability for the environment; thus, flaring and any test effluent become factors in the design specifications. This involves much lead engineering by well test designers to integrate the facility for use by the well test services. High activity levels and competition for the limited availability of equipment services and expertise is another frequent planning challenge. Market conditions in the oil industry also force operators to rely on old facilities for new tasks, that is, rigs. There is no doubt that the presence of any one or more of these features in a well test will qualify the test to fall into the definition. However, there are other factors less obvious except perhaps to department managers and to the well test planner. In many parts of the world, increasing demands for regulatory compliance add their own element to the challenging environment club.

ROLE OF THE WELL TEST ENGINEER

With the application of sophisticated modeling and new technologies to reservoir well testing, the role of decision makers planning and coordinating the various well test services is changing. In a market with limited access to experienced well test personnel, these challenges are compounded. One of the tasks of the well test engineer is to bridge the knowledge gap between different members of the resource company planning team and the contractors providing well test services. New technologies, such as high-resolution gauges, multiphase flow meters, and fiber optics, promise instant data, greater data quality, and other benefits not previously available to the reservoir modeler. Other new technologies, such as new generation burners and high-speed deepwater subsea test trees, promise tools that will overcome many of the physical challenges particular to some well environments. The result of this emphasis on test features comes at a price by placing demands on planning resources and in particular on planning schedules. The role of the well test engineer becomes increasingly specialized with the addition of new technologies and new techniques for working in an expanded range of environments.

NEW TECHNOLOGY

New technology presents its own challenges. Without a substantial track record, the planning team is faced with a new risk: that a new technology might fail to perform to specification and will result in a test failure, or at least a failure in some aspect of the test. New technology also represents change. The introduction of significant new technology results in significant changes to established and well-understood processes, replacing them with untried processes; in this regard, integrating them into the Well Test Program becomes part of the challenge to the planning team. The team concept comes into its own when the design has advanced significantly so that as much expertise as possible can review its complexities to ensure a fit-for-purpose design. At the beginning of this chapter, I indicated that the well test engineer must acquire an adequate knowledge of the well test environment in order to enhance planning. Ultimately, new technology might overcome some physical challenge or provide some extra data for the reservoir modeler. The challenge to those planning the test is to assess the business risk, specifically, the benefit provided by the new technology versus the cost of the technology, and the risks associated with departure from established processes. To meet this challenge, the resource company requires a knowledgeable team: able to anticipate the future, in control of the present, and with an understanding of the past. The planning team can only guarantee a quality process to get the data. In the end, the well test is a specialized operation combining many services into one task. However, the predictive character in the Well Test Engineer's role comes closer to the fore when dealing with difficult conditions and or new equipment. With anything new, experience and expertise necessarily comes with caveats, thus adding more gray and less definition to risk.

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Chapter | two

Well Test Services

CHAPTER CONTENTS

Much of the planning effort for a well test lies in the interaction between the well test engineer and the well test service contractors. In the sections that follow, emphasis is placed on the role and features of each well test service, including, where appropriate, equipment descriptions and the main design issues associated with each. This chapter also aims to show the importance of the role contractors play in the planning process.

WORKING WITH CONTRACTORS

The level of support during planning and operations is an important feature of any well test service. While the well test engineer identifies the need for a particular service, the engineer, the planning team, and the contractor contribute to detailed planning. A great deal of interaction between the well test engineer and the contractor might take place in order to arrive at a final design. Contractors offer a range of options in respect of equipment type, new technology, specification or method of deployment, and use. It is the well test engineer, representing the interests of the resource company, who reviews these options on the basis of their merit for technical suitability, value for money, reliability, and safety. In general, successful detailed planning requires face-to-face meetings between the well test engineer and contractor focal points. Issues such as engineering and systems interfaces, operational procedures, designs, and schedules are identified and resolved, perhaps over a number of meetings. A contractor focal point is a designated individual within a contractor organization assigned to liaise between the well test engineer and the contractor organization. The focal point has the necessary technical knowledge and experience to advise the well test engineer, who is the resource company's focal point.

PERFORATING SERVICE

A perforating service utilizes explosives to puncture holes into formation rock, usually through a cemented liner; the resultant perforation tunnels, created by the explosives, provide a flow path for reservoir fluid to travel from the reservoir rock into the test string and then to surface. Perforating service contractors provide the explosives and accessories that attach to the test tubing or to wire and are conveyed into the well to the depth of the formation. The contractors also

provide the expertise to supervise the loading, running, detonation, and retrieval of the perforating equipment and the support of a technical focal point prior to the job to discuss detailed planning.

Why Perforate?

The previous chapter observed that in order to maintain wellbore stability and to provide a pressure barrier; many well designs incorporate a cemented liner across the hydrocarbon bearing formation. Once a test string has been installed and commissioned, explosive charges are required to perforate through the cemented liner into the formation rock to establish the flow path described above.

Perforating Charges

Perforating charges are made up of explosive chemicals fitted into a specially designed steel casing, then covered with a liner. These shaped charges, when detonated, produce a high-pressure, high-velocity jet, the direction of the jet being dictated by the orientation of the shaped charge inside a carrier. The two principal measures that determine the effectiveness of the perforation are the depth of penetration of the jet issuing from the charge and the size of the perforation tunnel it makes into the formation rock. The larger the charge size, the greater the force creating the explosive jet. The exploding jet of material must penetrate the carrier gun containing the charge, the fluid surrounding the carrier gun, and the cemented liner before penetrating into the formation rock. The hardness of the rock resists the force of the charge. A skin — damage to the formation rock in the area around the wellbore caused by the drilling process and drilling fluids — produces an area of low permeability. If skin is known to be present or suspected, then it will be a perforating objective to penetrate past the skin (see Figure 2.1).

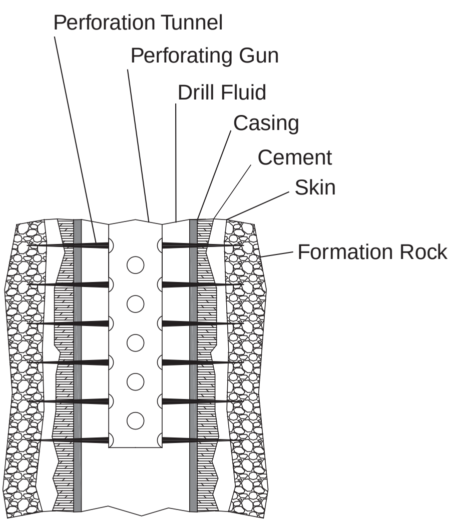


FIGURE 2.1 Cased Hole Perforation

In order to compare the effect of the various charges, the perforation contractor provides a perforation analysis report that describes the factors that influence perforations and indicates the likely penetration depth and perforation tunnel size for a range of available charges. Contractors specializing in perforation services conduct extensive testing of their products under controlled conditions. API RP 19B Evaluation of Well Perforators is a standard to which this type of testing is carried out and enables valid comparisons between products.

Wireline or Tubing Conveyed

One of the first decisions made in respect of the perforating service is that regarding the deployment method for perforating charges. Wireline-conveyed perforating services and tubing-conveyed perforating services have distinct advantages and disadvantages, and each method often requires a separate contractor.

In this matter the reservoir engineer has an important role to play, since the perforations contribute significantly to the effectiveness of production from the reservoir. The reservoir engineer's task is to provide the perforation intervals, that is, the top and bottom depths at which the guns are required to perforate the cemented liner. The well test engineer's task is to design a well test that ensures the guns are physically positioned on depth correctly for firing.

WIRELINE PERFORATION SERVICE

Perforating charges are lowered into the well through the test string, until they are at a depth corresponding to the depth of the reservoir formation rock. Once in position, the charges are detonated using an electric signal transmitted through the wire from the surface. Wireline-conveyed charges provide a great deal of flexibility in terms of speed of deployment and depth accuracy. The main drawback to this method of perforation is the limit to the size of charge since the internal diameter of the test string presents restrictions through which the wireline charges must pass. The size of charge is a critical factor in its effectiveness at opening access to the formation. In highly deviated wells above greater than about 55 degrees, this method of perforation is not an option since there is no means to push the wire down.

The wireline service is often a distinct contractor service to the wireline perforating service. Where they differ, the well test engineer should assess the interfaces between the two to ensure compatibility in the services, in particular with rope sockets, electrical resistance in the cable, cable length, and strength. Planning meetings involving the participation of representatives from both services and facilitated by the well test engineer are an effective means for managing these interfaces.

Wireline Operations

A typical wireline crew comprises a wireline engineer together with two or three wireline crew members per 12-hour shift. The size of the crew depends on the scope of work in the contract. When the contractor service for wireline perforating services is separate from the wireline services contract, additional personnel may also be required.

TUBING-CONVEYED PERFORATING SERVICE

Tubing-conveyed perforation (TCP) is the term used to describe charges that are fitted inside special tubing joints known as perforating guns and attached to the lower part of the test string. The positioning of the perforating guns across the target formation is achieved with the tubing spaceout. The charges are detonated with pressure applied from surface or a drop bar impacting a firing mechanism. The procedures for spaceout and detonation are described in Chapter 5.

A perforating gun is a length of tubing inside which charges are loaded at surface. Special carrier tubes retain the charges in position to ensure correct orientation inside the gun. Upon detonation, each exploding charge produces a high-velocity jet of pressure that travels perpendicular to the axis of the gun and penetrates the gun shell, the cemented liner, and the formation rock, the result is an open tunnel through which reservoir hydrocarbons can flow into the test string (see Figure 2.1).

Perforation tunnels penetrate beyond skin damage and effectively provide a greater surface area to flow than the equivalent length of open hole. There is no practical limit to the length of guns that can be run in this manner, and only the bore of the liner restricts the gun/charge size.

Size and Type of Charge

The size of the charge is limited by the size of carrier gun, which in turn is limited by the casing or liner size. After detonation, guns swell in diameter owing to the force of detonation and to the damage to the gun casing produced by the perforations. This swelling should be taken into account when considering a suitable gun size for a given casing. Apart from the size of charge, the type of charge is influenced primarily by the expected temperature of the well. Explosive charges are essentially a composite mix of chemicals. Up to certain temperatures, the charges are stable and can be relied upon to behave consistently to specifications. However, above their rated temperature, the charges begin to deteriorate and can become unreliable. A standard HMX charge will typically perform to specification at up to 150 Celsius for 100 hours. For most well tests, 100 hours is ample time to install and detonate the charges. However, above 150 Celsius, HMX charges deteriorate rapidly and high-temperature HNS charges with a

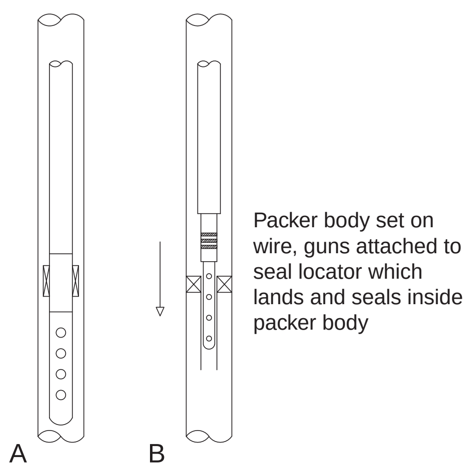
different chemical composition are required. Some performance in the charge is sacrificed to achieve the high-temperature specification. High temperature HNS charges are generally less available than standard HMX charges, and additional lead time is required for ordering.

Deployment

TCP guns can be deployed either on the bottom of the test string or suspended from a separate device such as a packer or anchor tool (Figure 2.2).

Figure 2.3 shows a typical TCP assembly suspended from a test string. From the bottom, a bullnose provides a rounded end face to reduce the chances that the guns will hang up on any internal upsets in the well during installation. Guns are typically available in standard lengths of 3 m and 6 m. Lengths are joined together using special intercarriers that accommodate the detonation cord and booster charge necessary to provide continuity between the guns to ensure every gun detonates simultaneously. At the top of the gun assembly, a section of blank gun, a minimum of 3 m length, is attached before making up the firing head section. This blank gun is referred to as a safety spacer; its purpose is to ensure the top charge in the gun assembly is below the rotary table, and hence below the level where personnel are standing, as the firing head is fitted. This feature is provided as a safety measure in the remote event the guns accidentally detonate at surface. Above the firing head is a gun release mechanism or drop sub, this device is designed to separate, either manually using a slickline-conveyed shifting tool or automatically when the guns detonate. When activated, this device detaches the entire gun assembly below, allowing the guns to fall to the bottom of the well. This feature facilitates access to the formation for wireline operations. Examples include production

FIGURE 2.2 (a) & (b) TCP Guns Deployment



logging tools, electronic gauges, and sample tools. This feature may also be used to provide access for wireline-conveyed guns to provide additional perforations or as a contingency perforation method should the TCP guns fail to detonate. In many instances, it might be cheaper to release the TCP guns whether or not wireline operations are planned, since the removal of the spent guns at the end of the test is a critical path activity that may take a number of hours.

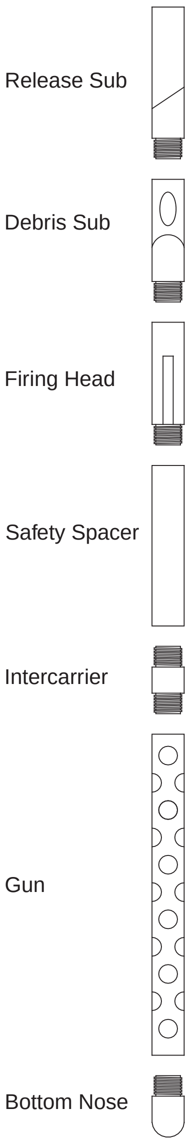


FIGURE 2.3 TCP Assembly

The above method of deployment assumes a retrievable packer, that is, a packer that is conveyed and retrieved with the test string. However, it is not always possible to utilize a retrievable packer, particularly in cases where conditions of extreme temperature and differential pressure may act on the packer seals. In such cases, a very different type of packer, a seal bore packer is required for the operation. Figure 2.2a illustrates an alternative method of deployment for TCP guns using a permanent seal bore packer. The packer with seal bore is set inside the liner prior to the installation of the test string. A locator section that seals inside the bore of the packer is fitted to the test string. When the test string is run in hole, the seal locator sits inside the packer seal bore providing a seal between the annulus and tubing downhole. TCP guns may be attached below the locator assembly, but are necessarily limited in size to fit through the seal bore of the packer.

TCP guns can optionally be attached to the bottom of the seal bore of the packer itself and be installed with the packer body prior to the test string.

The advantage of attaching TCP guns to the bottom of the seal bore is that a gun of any size may be installed, restricted only by the internal diameter of the liner. However, this method of deployment also has a number of disadvantages. First, the packer, seal bore, and guns add up to a substantial weight. Without the additional weight of the guns, most seal bore packers can be set on wireline, an operation that may take 3 to 4 hours depending on well depth. Except for short TCP gun lengths, it is likely that the packer with the added weight of the guns would have to be set using tubing or drill pipe. This operation may take 12 to 18 hours depending on the well depth. Second, should the guns fail, there is no practical contingency to run additional TCP guns since most seal bore packers cannot be retrieved. There are exceptions, and these are discussed in the section on downhole tools. Finally, the exposure time of the charges to bottomhole temperature is limited. Guns conveyed below the packer before the test string are exposed to bottomhole temperature for a considerable time until the test string is installed and the guns are detonated.

Firing Heads

Firing heads are mechanisms that trigger the detonation of the perforating charges inside the guns. The charges are linked to the firing head by means of a detonating cord, which is itself an explosive material. The detonating cord, which has the appearance of an electrical cord, is attached to each of the charges in the guns and threaded along the inside of the guns to the firing head where it is connected to a percussion detonator. Where several guns are connected together, breaks in the detonating cord are joined together using a booster charge, which assists in transmitting the detonation from one gun to the next.

The percussion detonator in the firing head is activated with pressure or a drop bar. With a pressure-activated firing head, tubing pressure above a preset value is applied to the firing head to burst a rupture disc or shear a pin. This exposes the firing head to hydrostatic pressure, which acts to drive a hammer onto the top of the percussion detonator, which in turn detonates the guns.

A drop bar can be used in place of surface-applied pressure. A drop bar might be used where the test string is only partially filled with fluid or where a nitrogen cushion is used to provide the required cushion. Controlling pressure on the firing head would be difficult in these circumstances. A drop bar, as its name implies, is simply a steel bar with a prong at the bottom. The bar is released into the test tubing, taking care first to ensure that the test tubing valves are open to the firing head. The bar falls onto the firing head, and the impact of the prong on the firing head initiates the detonation.

It is common practice to incorporate a time delay into the pressure-activated firing head. A time delay performs two functions. First, it allows time for the firing head activation pressure to be bled off; otherwise the reservoir might perforate with excessive pressure acting on the formation, overbalanced due to combination of hudrostatic fluid pressure and the additional surface-applied pressure acting on the test string to initiate detonation. Second, the time delay facilitates a clear indication that the guns have fired because all other activity at surface associated with bleeding down the activation pressure will have ceased.

CONTINGENCY PERFORATING

Planning should include contingency against gun failure. Wireline guns may be acceptable to the reservoir engineer as backup to a TCP system. However, if their performance is deemed inadequate, it may be necessary to plan to retrieve the test string and rerun a new TCP system. This is a costly contingency, so any measure that improves the reliability of the primary system is worth the investment. Some firing heads can be retrieved using wire. Special tools run inside the tubing locate and retrieve the firing head to surface without the need to retrieve the entire test string. Installation of a dual or redundant firing head system also provides additional reliability to the system.

DEPTH CONTROL

TCP guns attached to a packer and set on wireline are easily positioned since the wireline provides depth control through the use of a casing collar locator and a gamma ray signal, both of which can easily reference markers in the casing and the formation. If TCP guns are conveyed below a retrievable packer, then the depth control becomes a little more difficult. A simple tally depth, which basically adds up the length of all the test string components to provide depth control, is prone to error. This type of depth control may

be adequate if the perforation interval is great and a few meters one way or the other is not a concern. For precise depth control, however, it is often necessary to run a gamma ray correlation through the test string before setting the packer, in order to make fine adjustments to the gun depths.

TUBING SERVICES

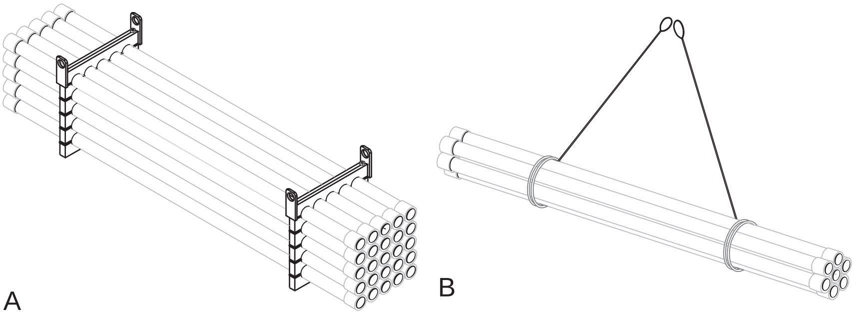
A tubing service has two components: the supply of rental tubing and the supply of tubing handling services. The tubing utilized during a well test is not consumable; it is recovered after the test and is used again elsewhere, though some resource companies own and manage their own test tubing. In general, it is rented from contractors specializing in tubing services.

As a product, tubing comes in a range of standard sizes and materials, with a range of connection types according to the tubing vendor. Tubing supplied to the oil and gas industry is collectively referred to as oilfield country tubulars. API 5CT Specification for Casing and Tubing is a widely recognized standard governing the manufacture and specification for this class of tubing. In addition to the specifications in this standard, most well test applications involve the use of tubing with so-called premium connections. These are high-specification connections with excellent gas pressure seal capabilities. Premium connections are proprietary thread connections with specific handling procedures provided by the manufacturer. Their high reliability is achieved through use of a number of quality control measures. The cutting of premium threads is strictly controlled through the issue of special licenses issued by the vendor.

Tubing Handling

The storage and care of tubing requires specialized skills. Thread connections and seal faces require inspection from qualified personnel to ensure their readiness for use. Corrosion and damage due to poor storage or handling can result in expensive wastage or, worse, failure when in service. A buildup of corrosion inside the walls of the tubing may result in debris accumulating in a well and also in downhole tool failure during service.

Manufacturers provide detailed handling and make up procedures for every type of tubing. These procedures entail the use of specialized equipment that controls makeup torque to within the optimum limits specified by the manufacturer. Handling procedures cover transportation and lifting, storage, use of protective coatings and lubricants, stencilling with traceability information, correct use of thread end protectors, and thread inspections. Installation procedures include data on the use of makeup lubricant, commonly referred to as dope, makeup torque and makeup length — that is, the change in overall length of the tubing due to the makeup loss on the thread. The tubing vendor also supplies other important information such as strength and dimensional data.



A B

FIGURE 2.4 (a) Tubing Wine Rack (b) Tubing Bundle

Tubing contractors supply premium tubing either in bundles or in shipping racks. Bundled tubing is gathered together with wire rope slings, which are secured when lifted in tension to prevent the tubing joints from spreading. A typical bundle is made up of about 10 joints of tubing. A preferable shipping method uses special racks that separate the tubing joints from one another using plastic or wooden spacers. These are clamped together to secure individual joints. Shipping racks provide better protection for the tubing because they prevent joints from contacting one another. This is particularly important for high chrome content tubing, which is used in highly corrosive applications. Figure 2.4 shows the two methods for lifting tubing.

Types of Tubing

Tubing intended for well test applications is generally supplied in standard lengths of about 9.75 m each, so called range 2 tubing. Some variation in length between joints is permitted. The lengths indicated are always overall lengths. Along with full-length tubing joints, a well test engineer orders a selection of shorter joints known as pup joints. Pup joints are useful for adjusting the length of the test string and for use as handling and saver joints on assemblies and test tools.

Except for low-pressure environments, most well test applications require tubing with premium thread connections. API provides an industry recognized shorthand to specify a particular tubing type. The following example is a premium connection frequently utilized in well test applications.

3½ in. PH6 12.95 lb/ft L80.
3½ in. is the nominal outside diameter of the tubing.
PH6 is the connection type, in this instance a hydril premium connection.
12.95 lb/ft is the weight of the tubing in pounds per foot.
L denotes the tubing material.
80 is the tubing yield strength in thousands of pounds per square inch, in this instance 80,000 lbs/in^2.

Selecting the correct tubing for the test is an important aspect of the test string design. The strength of the tubing must safely contain well pressure under the conditions of temperature, fluid type, and load conditions, while the size of the tubing must be selected to suit production conditions. The reservoir engineer conducts nodal analysis, which models the behavior of fluid in the test string based on expected conditions. This type of modeling compares the effect that different sizes of tubing will have on production rate, pressure, and temperature. This information assists the planning team when selecting the tubing best suited to the job. Availability and cost also factor into the selection criteria.

Tubing Handling On Site

On-site operations require tubing handling services. Tubing service contractors specializing in this area provide experienced personnel trained in the handling of oilfield tubing. Tubing handling equipment is also provided as part of the tubing handling service.

The typical tubing handling services crew consists of two to three persons per 12-hour shift. The tubing handling services crew supervises every aspect of tubing handling on site. In addition, they monitor the tubing tally to ensure the correct amount of tubing is run in hole.

DOWNHOLE TOOLS SERVICE

The primary features of the downhole tools service are control of annulus and tubing communication and downhole shut in.

The service includes the equipment necessary to achieve the above objectives and the expertise necessary to prepare, install, and operate the tools in the well, as well as provide planning support prior to the well test. This includes technical advice on the type of tools required for each application and the procedures necessary to install and operate the tools.

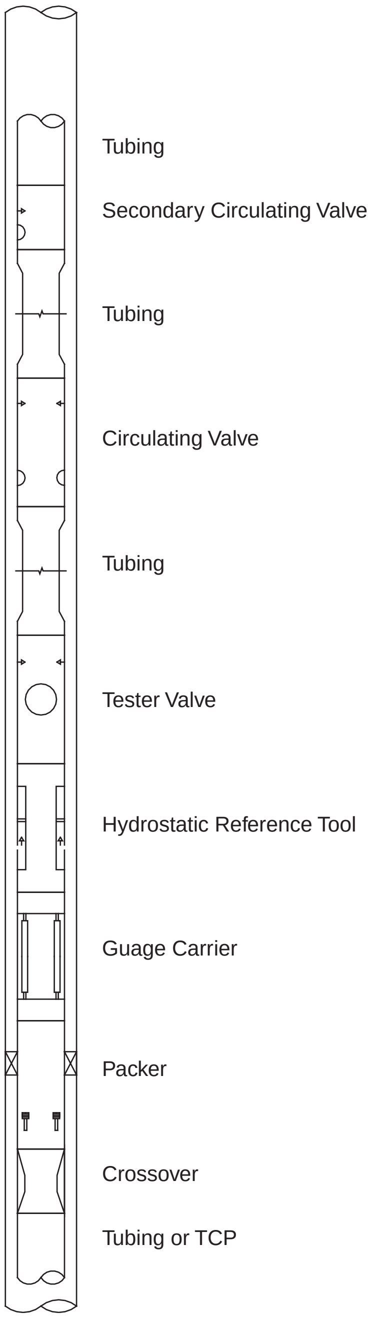
Control of Annulus and Tubing Communication

Control of annulus and tubing communication requires different tools in the test string, a packer, a re-closable valve between the annulus and tubing above the packer, and a backup valve.

The packer anchors the bottom of the test string to the casing and provides a barrier between the annulus and the reservoir.

During the setting process, elastomers in the packer extrude against the casing wall or liner to form a seal. At the same time, a set of slips extend from the packer body to anchor against the casing. This permits the packer to take axial loads either compression loads acting to push the packer down or tension loads acting to pull the packer up, or both, depending on the design of the packer. These loads act on the slips and not on the seals.

FIGURE 2.5 Downhole Test Tools



Although quoted with a number of specifications by the supplier, the ability of a packer to contain differential pressure across the seals is dependent on a number of variables, the condition of the casing, the type of well fluid, and the temperature. The elastomers in the packer are selected to suit the conditions, though at high temperatures and in the presence of high levels of CO_2, some loss of strength in the seals may occur over time. The condition of the casing is equally important; it is possible that debris or cement may be present when the packer is set, providing a potential weak point at the seals. Many resource companies run a casing scraper to remove debris and circulate clean fluid at the setting depth prior to running the packer as a quality control measure.

The fit of the packer within the casing is another factor. Seals must extrude to fill the gap between the packer and the casing. Some packers, particularly retrievable packers, are designed to fit a range of casings and consequently may not have an optimum fit for every size of casing. High-specification packers such as permanent packers, on the other hand, are manufactured for specific casing sizes and often have anti extrusion rings, which support the packer casing seals. As a result, the seal is more reliable, making this type of packer better suited to harsh conditions.

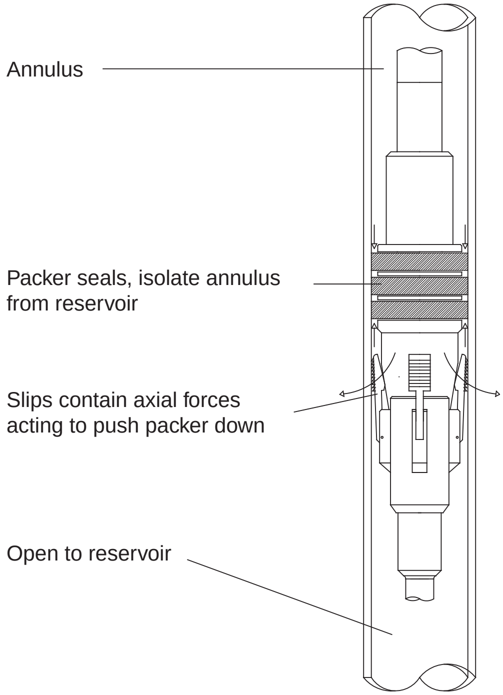


FIGURE 2.6 A Typical Well Test Packer

The two most common packer types used in a well test application are the retrievable packer and the seal bore permanent packer. A retrievable packer uses a J setting mechanism, which requires string rotation and compression weight for setting.

It is necessary to maintain setting weight on a retrievable packer throughout the test as this type of packer is designed to release from the casing when placed in tension. Telescopic slip joints are required as an accessory with this type of packer because the setting procedure incorporates vertical string manipulation; this means that once the packer is set, some movement of the string will be necessary to reposition other tools such as the subsea test tree and the flowhead. Telescopic slip joints also accommodate expansion and contraction of the test string due to temperature and pressure effects. Because of the presence of the telescopic slip joints, and the need to maintain setting weight on the packer, heavyweight drill collars are an additional accessory required between the slip joints and the packer to provide the needed setting weight.

Seal bore permanent packers are frequently used in place of retrievable packers where downhole conditions are more extreme and greater reliability is required. The differential pressure across the packer seals, the test fluid, and the bottomhole temperature are factors that can direct the planning team to utilize this type of packer. A seal bore packer has two principal components. First, the packer body, which incorporates the casing seals and anchor section, the packer body also incorporates an internal seal bore. The packer body is initially set on wireline or pipe, prior to installation of the test string. The second component, the seal section or seal locator, is run with the test string and is designed to locate and enter the seal bore of the packer body. In this configuration, the casing seals isolate the annulus from the wellbore below the packer, while the seal locator isolates the annulus from the tubing. The seal bore length in the packer body can be adjusted by adding additional sections. The seals in the locator are free to move inside the seal bore. Because of this, and because this type of packer does not require weight to maintain its integrity, none of the other accessories of slip joints and drill collars are required. Although considered more reliable and requiring fewer accessories, a disadvantage of this type of packer is the fact that the packer body requires an additional run into the well to set it. In addition, the packer body cannot be retrieved at the end of the test, which is not always desirable — for example, if the resource company intends to suspend the well in order to utilize it later for a completion.

It is important for the test engineer to decide on the right packer system early in planning because this decision will influence many other features of the test design, including the procedure for deployment of TCP guns, the requirement for wireline services to set a permanent packer, and the well suspension procedure.

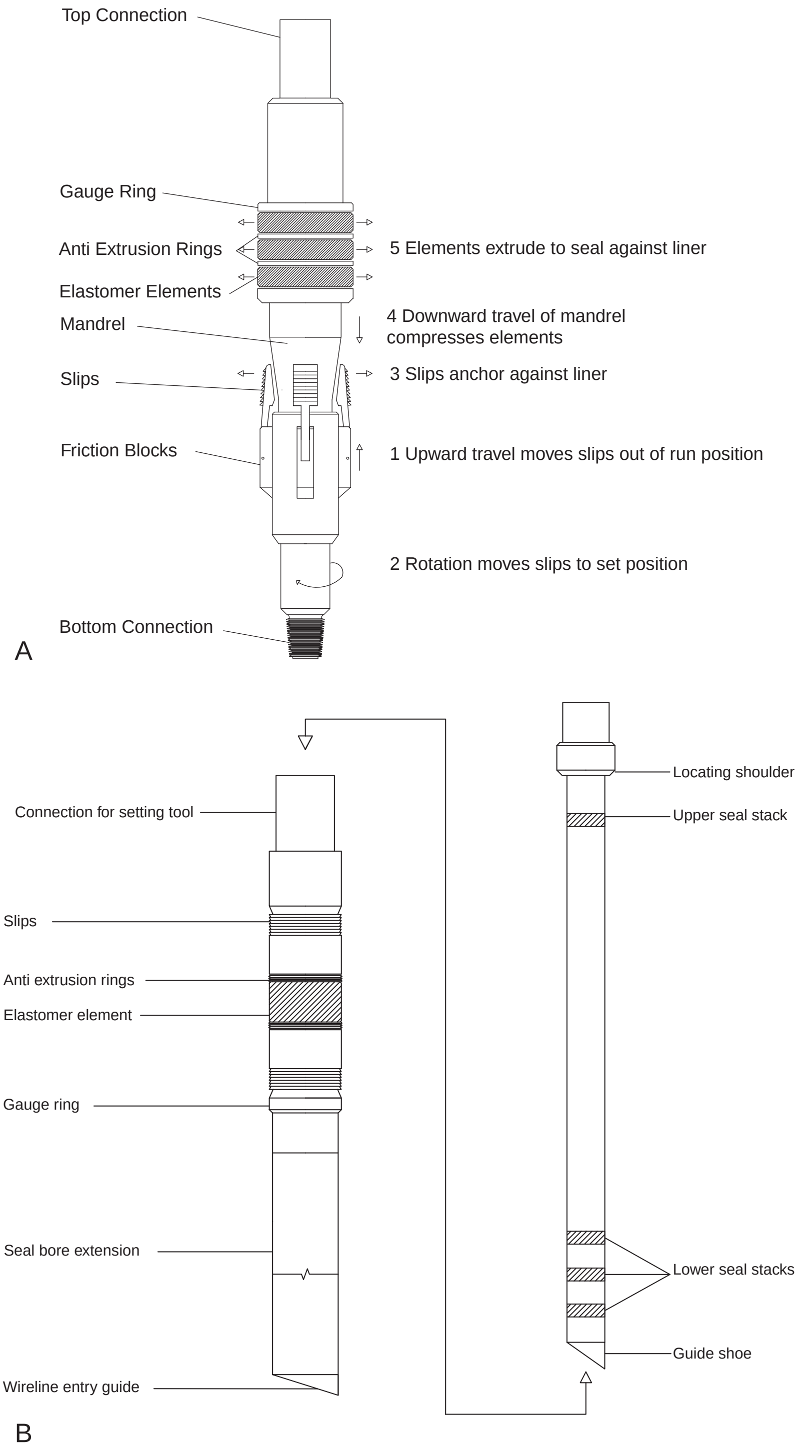


FIGURE 2.7 Seal Bore Packer

Other than the packer, control of the annulus to tubing communication requires that a valve be situated above the packer that can open and close as required for a range of different operations. During a well test, it is frequently necessary to pump fluids from the tubing to the annulus, circulating, and to pump from the annulus to the tubing, reversing. This type of valve typically operates with annulus pressure, which acts on a sleeve inside the tool, which in turn covers and uncovers a set of ports that open communication between the annulus and tubing. Different sets of ports are fitted with check valves to control the direction of fluid flow; continuous cycling of the tool uncovers alternate sets of ports depending on which direction flow is desired. A further cycle of the tool closes both sets of ports. In order to accommodate the fact that pressure cycling in the tubing and annulus will occur for reasons other than the operation of this valve, the cycling mechanism includes a number of blank cycles that allow pressure to be applied to the well without opening this valve. The number of blank cycles can sometimes be varied, but typically five blank cycles are permitted before the tool opens to the circulating or reversing position.

The function of the annulus to tubing valve is an important one, for it facilitates a number of critical operations. However, because of the features required of the valve, it is inherently complex, with a number of moving parts that are sensitive to external conditions, in particular the medium in the annulus used to transmit pressure to the tool from surface, including the cleanliness of that medium and the general cleanliness of the casing. For this reason, it is a best practice to include a backup valve in the test string which provides a simple means of establishing annulus to tubing communication in order to have the facility to control the well with annulus fluid. This backup circulating device is typically a simple rupture disc-operated device, which, when activated, permanently opens two-way communication between annulus and tubing.

Downhole Shut In

The second principal objective of the downhole service is downhole shut in. A downhole shut-in valve, also called a tester valve, is located as low as possible in the test string, usually a short distance above the packer. When closed, this valve isolates the wellbore below the packer from the tubing. Electronic gauges provided by a separate service are positioned below the tester valve, or positioned so as to sense pressure below the tester valve. In this manner, the data recorded on the gauges is not influenced by hydrostatic effects in the tubing, thereby providing an improvement in data quality.

This tool also provides a barrier in the test string. The tester valve, which is normally opened with annulus pressure, is designed to fail close once annulus pressure is bled off. Given the depths at which the tester valve must operate, and given the hydrostatic forces acting on them due to the weight of the

annulus fluid, the operating mechanism required to open the valve and the spring force required to close it again must be designed to accommodate the effects of hydrostatic pressure. This is achieved using a hydrostatic reference tool, which is attached directly to the tester valve. As the tool runs into the well, the hydrostatic weight of the annulus fluid acts on a piston inside the reference tool and compresses a charge of nitrogen behind the piston. Once on depth, the nitrogen charge is trapped by manipulating the string or by rupturing a disc that traps this reference pressure. The trapped pressure acts as a spring, exactly balancing the effect of hydrostatic pressure so that the tester valve will subsequently operate with a known applied surface pressure and close again when that pressure has been bled off, using the compressed nitrogen to assist.

It is also convenient to build into the tester valve a lock open feature, so that after a number of open-close cycles, the valve remains in the open position without annulus-applied pressure. This feature is useful, for example, when retrieving the test string at the end of the job, to allow fluid out the bottom of the string as the tubing is pulled to surface.

A number of other tools may be included along with the downhole tools discussed above. Including gauge carriers and sample tools, although they do not perform part of the primary objectives of the downhole tool services, they contribute to the overall well test objectives, and because they are downhole tools they are normally managed by the downhole tools service. These tools are discussed in the sampling and data acquisition sections of this chapter.

New Technologies

New technologies applied to the downhole tool service provide superior elastomers and tool components, resulting in tools that perform better in more hostile downhole environments. Many downhole tools are now dressed with elastomers that can routinely work at temperatures up to 220 Celsius. Other applications of new technology include the use of electronic devices that convert low-pressure annulus signals into preprogrammed valve movements, doing away with the high pressures normally required for annulus-operated tools. These tools incorporate the features of both the tester valve and the annulus-tubing communication valve.

During the well test design stage, the well test engineer will liaise with the downhole tools service focal point to select the tools and operating parameters best suited to the test. Factors to consider include the tool connection type, including crossovers to the test tubing, packers and perforating system, operating pressures, seal selection, internal and external diameters, the tensile strength of each tool, and fishing dimensions. The well test engineer will also review the operating procedures for each tool in order to integrate them into the well test program.

For well site operations, a crew of two downhole tool specialists is normally adequate to conduct the operation. Two complete sets of tools with spares is standard in the event of a downhole failure and the need to have a set of tools ready immediately to re-run.

SUBSEA SERVICE

The subsea service performs an important safety function during the well test on floating offshore facilities. The primary objective of this service is to provide equipment that will isolate the test string and disconnect the upper test string at the seabed, without interfering with the function of the facility's blowout preventer (BOP). This safety feature is a contingency in the event of an emergency that does not permit enough time to kill the well and retrieve the test string normally, such as the approach of severe weather.

Subsea Test Tree (SSTT)

The tool that facilitates this objective is the SSTT. This tool, or rather assembly, comprises a number of discrete features, each of which contributes to its ability to interface the facility BOP while retaining the features that enable it to close and disconnect quickly. Figure 2.8 illustrates the main components of this assembly and indicates how the assembly sits inside the facility BOP.

The fluted hanger at the bottom is a doughnut-shaped nut that sits in the profile of a wear bushing. This is the land-off point of the test string in the wellhead, the entire test string is sometimes suspended from this point. Above the fluted hanger is the slick joint. This length of pipe is sized to fit the BOP rams of the facility and is spaced so as to sit opposite at least one set of rams when the fluted hanger is landed off in the wear bushing. An annulus seal is formed when the rams are closed on the slick joint. With the rams closed, the annular space below the BOP is isolated, except through the choke or kill lines on the BOP. The choke and kill lines permit control of the pressure in the annulus using the rig pumps or the cement unit (see Figure 2.8). Above the slick joint, the valve section of a subsea test tree is designed to fail close and is opened using hydraulic pressure supplied through an umbilical control hose. The valve section itself may incorporate a dual ball or ball and flapper combination. The dual seal design is provided because the valve may close during wireline operations, which can score or damage a ball as it closes and cuts the wire. The second ball or flapper normally closes a short time after the first one, allowing time for the severed wire to pull clear of the second valve. Directly above the valve section is the hydraulic section, which incorporates the disconnect feature. When activated using hydraulic pressure applied through the umbilical from a control unit at surface, the hydraulic section disengages from the valve section. The hydraulic section and the tubing above can then be retrieved to surface while the valve section remains closed

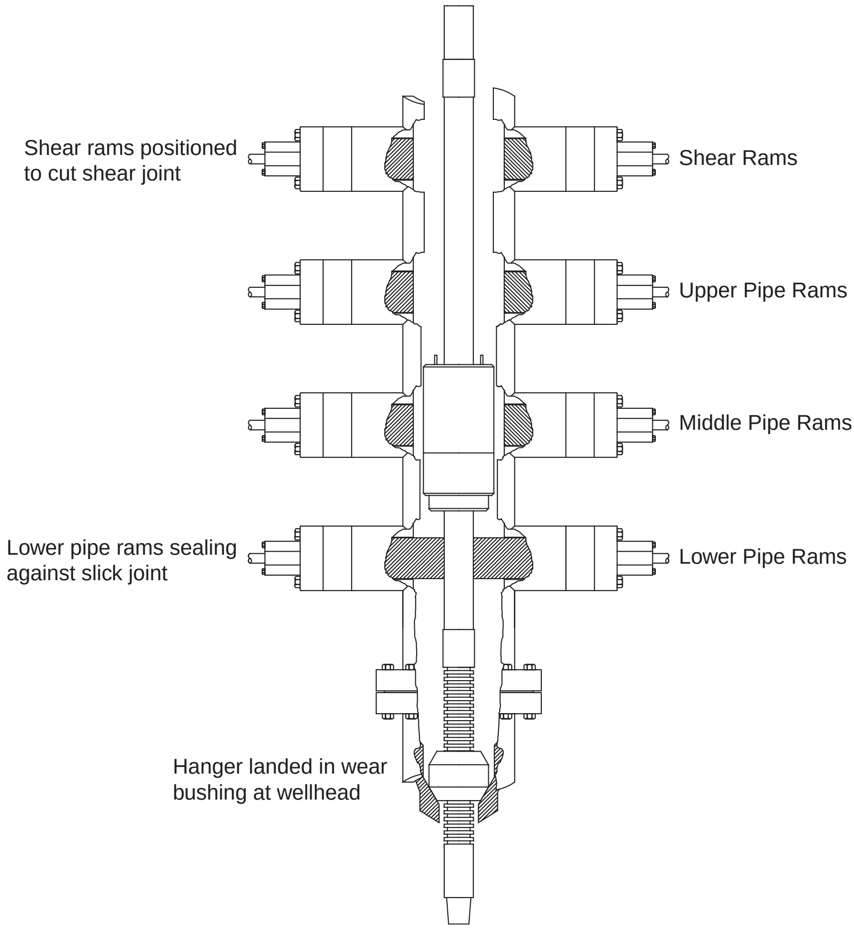


FIGURE 2.8 SSTT Inside BOP

isolating the test string below. Once clear of the BOP, the blind or shear rams of the BOP can also be closed to provide an additional barrier. If need be, the LMRP can disconnect from the BOP, allowing the facility to move off location.

Other than for well control purposes, the ability to close a barrier in the test string is useful in applications where long wireline tools have to be assembled using the landing string or tubing above the BOP as a lubricator, which is the term used to refer to a volume of tubing or pipe that can be isolated and depressurized.

Deepwater Operations

The disconnect time in an emergency is dependent not only on the nature of the emergency but also on the facility, specifically on a dynamically

positioned rig. Fast disconnect times of the order of 10 seconds are required due to the nature of the automatic disconnect features built into the vessel's design features.

Water Depth

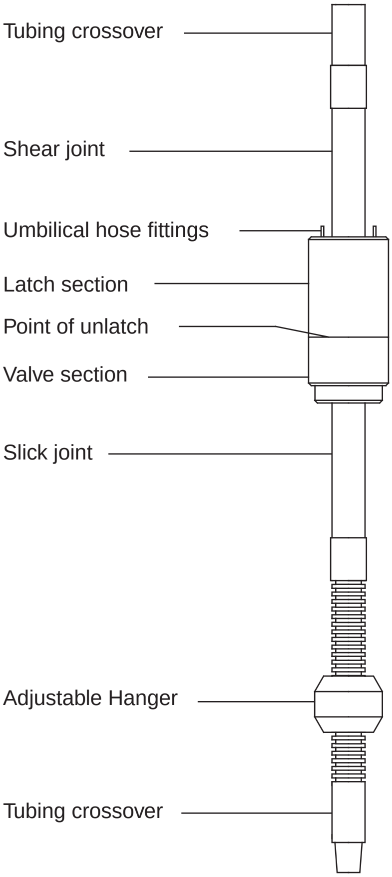
Water depth influences other specific features of the subsea test tree design. As the water depth increases, so too does the weight of the umbilical control hose, which must be run with the SSTT. Attaching the hose securely to the tubing requires the use of specially sized clamps following a specific procedure, which adds to the installation time of the test string. In the case of a gas well test, a chemical injection umbilical hose may also be run with the SSTT. An injection point in the valve section permits injection of chemicals such as methanol into the tubing to assist with hydrate prevention. Given the exposure of the umbilical hose to damage every time the slips are set, or due to rubbing against other edges as a result of rig movement, it is advisable to have a contingency hose on hand or at the very least, the means to repair the umbilical hose in the event of damage.

Another consideration in deep water is the effect of hydrostatic pressure in the riser on umbilical hoses. The hoses are made from a combination of synthetic materials that are flexible enough to coil onto a spooler and at the same time strong enough to contain the hydraulic pressure required to operate the SSTT. However, as the hydrostatic pressure in the riser increases with water depth, so too does the risk of damage to the hoses due to the effects of this pressure, which tends to crush the hose. The design of the hydraulics in the subsea test tree can be altered to allow the umbilical to maintain a positive pressure on all functions during installation and operation so as to counter the effect of hydrostatic squeeze on the umbilical. Some steel-reinforced umbilicals are available with an increased resistance to collapse under pressure. This type of solution is good for water depth up to around 600 m. However, as the depth increases, transmitting hydraulic signals to the SSTT in emergencies requires assistance, either by using accumulators or by replacing the all-hydraulic SSTT control system with an electrohydraulic system that utilizes an electric signal from surface to a hydraulic accumulator downhole near the SSTT. These systems more readily achieve the 10 second operation time required for the deepest applications.

In addition to the SSTT, a lubricator valve is generally run as part of the subsea service. This is a simple hydraulic ball valve that is opened or closed with a separate control umbilical. The lubricator valve isolates the top few joints of tubing in the landing string to permit depressuring the tubing to allow installation of wireline tools.

A pump trough feature is available with most SSTT valves. This feature provides that in the event of tool failure — for example, because of damage to an umbilical — the valves of the subsea test tree permit fluid to pump into

FIGURE 2.9 Subsea Test Tree Assembly



the test string from above, provided all hydraulic pressure has been vented and the pressure from above exceeds a predetermined ball-opening pressure.

Well site operations are normally manned with a single subsea tools specialist, who is generally assisted by the surface well test service crew inasmuch as these two services are frequently provided together. For deepwater operations, however, two specialists will be required to provide 24-hour coverage.

SURFACE WELL TEST SERVICE

The surface well test service provides the personnel and equipment necessary for handling, metering, and disposing of produced well fluids.

The range in flowing conditions and fluid properties produced during a well test requires flexibility in the process equipment. Unlike the process equipment utilized in production facilities, well test equipment is not manufactured specifically to suit a set of conditions or fluid properties. Surface well

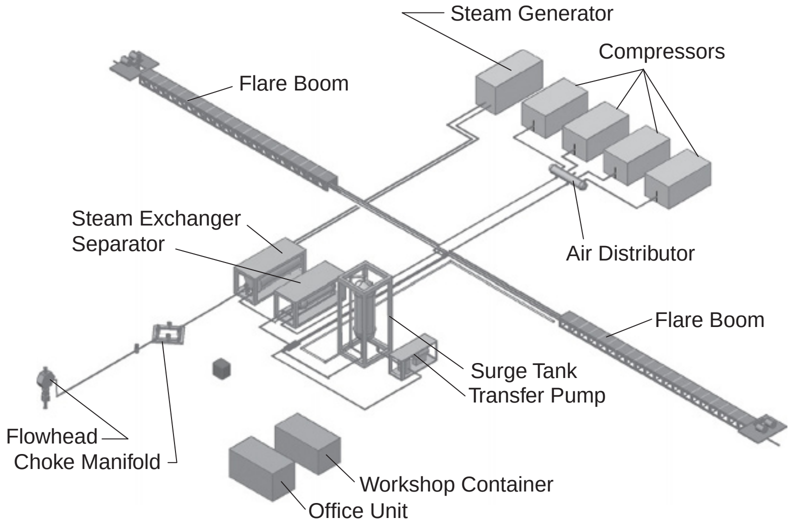


FIGURE 2.10 Well Test Equipment Pressure Nodes

test equipment is modular, and components can be interchanged to suit different needs. The range of conditions and fluid properties is discussed in detail in the next chapter along with the methods available to handle each. Figure 2.10 shows a typical surface well test equipment setup.

The high-pressure equipment between the flowhead and choke manifold is designed to contain maximum shut-in wellhead pressure. As its name implies, the choke manifold chokes or restricts the flow of the produced fluid, reducing the flowing pressure to a level that is within safe working limits for the low-pressure equipment downstream. It would be impractical to manufacture equipment such as separators, pump, and burner heads to operate at high pressure; it is much easier to reduce the pressure to a more manageable level. After the choke manifold, the low-pressure mixed fluid is passed through a heat exchanger in order to raise its temperature. Heating well fluid often assists fluid handling, reducing the viscosity of heavy oil, for example, or helping to prevent the formation of hydrates during a gas well test. After the heat exchanger, mixed fluid enters the separator where it is divided into two or three phases depending on the fluid makeup, oil, gas, and water, with each phase metered as it leaves the vessel. Recombination and non-pressurized samples for analysis are also taken from the separator; sampling is discussed separately in the next section. After the separator, the gas phase travels to a discharge line on a flare boom, which extends from the side of the rig. The gas is ignited and flared as it exits the end of the boom. Oil exiting the separator may be directed to a tank for additional measurement and then pumped to an oil burner head that is also mounted at the end of the flare boom. Oil may also be sent to the burner head directly from

the separator for flaring, provided there is sufficient separator pressure to drive it. The next chapter expands significantly on this section since there is a significant role for the well test engineer to interact with this service during planning and operations.

Safety Systems

During a well test, personnel operating and monitoring process equipment work in close proximity to hydrocarbons under pressure. In order to manage the risks associated with the accidental release of hydrocarbons under pressure, various safety systems are designed into the process to protect personnel.

The overall approach to the design of the safety system is outlined in a well test safety system philosophy, which defines different levels of protection in the process as unsafe conditions escalate. Typically, the first level provides for manual detection and intervention by an operator. An operator, in continuous attendance, may observe an unsafe condition such as a high tank level in danger of overflowing. The operator will intervene manually if the condition cannot be controlled normally and will activate a manual emergency shutdown device isolating the test equipment from the production source. A second level of safety operates the shutdown system automatically using sensor switches, while the third level vents production to a safe area in the event pressure rises rapidly to an unsafe level and threatens to exceed the safe working pressure of the test equipment. A systematic approach to the design of a safety system is detailed in the standard API RP 14C Recommended Practice for Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms.

A key safety device in the process equipment is the emergency shutdown (ESD) system, designed to shut down well test production quickly in the event a situation occurs in the facility that makes it unsafe to continue testing. In line with the safety system philosophy, the ESD incorporates manual and automatic shutdown features designed to operate the well test equipment. This system does not normally interface other systems on the facility.

A typical ESD system controls two normally closed hydraulic valves in the high-pressure production line. Upon activation, the valves are closed either simultaneously or in sequence, according to the system design. The pump providing hydraulic pressure which holds the valves in the open position is in turn controlled with pneumatic pressure. This control pressure can be bled manually or automatically. Manual switches are located in key positions, readily accessible to personnel in continuous attendance around the test equipment and the facility. Automatic switches are fitted to various points in the well test process equipment and sense the operating pressures at each point. Once the pressure exceeds a preset value, the switch automatically activates the ESD.

If a steam boiler is present as part of the well test package, then it is common practice to connect the ESD system to the boiler so that the boiler

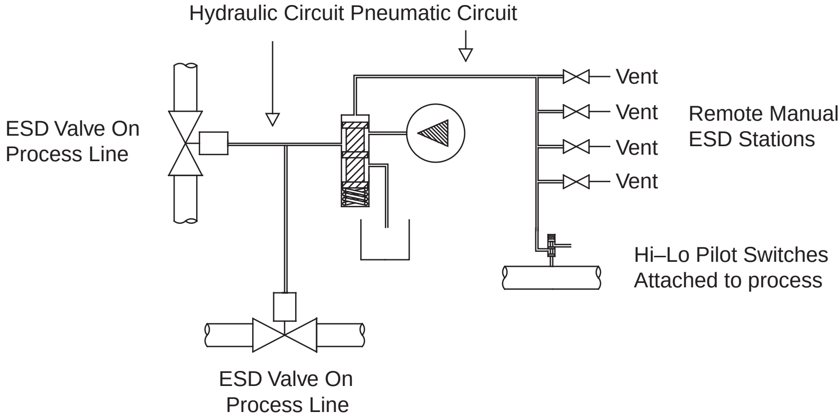


FIGURE 2.11 ESD System

automatically shuts down in the event of an ESD operation. The pneumatic pilot hose is made of fusible material designed to melt in the event of a fire and activate the ESD automatically.

The third level of safety, automatic pressure relief, is provided by pressure safety valves (PSVs) installed at key locations in the test setup. A simple PSV is a spring-loaded valve that is normally closed. The spring tension can be adjusted to a preset level, so that the valve opens as soon as the pressure acting on the valve exceeds the preset value. Other types of valve operate with different mechanisms but achieve the same end; that is, they relieve pressure from a pipe, a vessel, or any other pressure-bearing device, once the pressure exceeds a preset value.

In addition to defining the levels and type of safety redundancy, the safety system philosophy may go on to detail response times, standards, calibration frequencies, and placement of safety devices.

The planning team, including the well test contractor, assesses the expected well test conditions and considers the surface equipment configuration to best manage the expected conditions. All of the equipment should be sized to suit pressure, temperature, throughput, and all the other environmental conditions discussed in the previous chapter. For example, if the expected flow rate of oil is high, then the type of burner used must be capable of efficient combustion at high rates. The consequences of the burner not operating efficiently are incomplete combustion and environmental pollution.

Metering of the well fluids is critical to achieving the test objectives. Viscous, foaming, or waxy oil and hydrates in gas could impair metering equipment in the separator, and without special measures such as heating of the fluid or injecting special chemicals to reduce foaming, emulsion, or hydrates, accurate metering becomes difficult.

Chapter 6 describes a comprehensive approach to safety during well test planning and includes a description of the process for designing the safety systems for the well test equipment.

SAMPLING SERVICE

The sampling service, traditionally supplied as part of the surface well test service, has become a highly specialized service in its own right. The sampling service contractor manages the sampling process from the preparation and supply of sample containers and specialized equipment to the procedures and training of personnel to acquire the samples and the subsequent transportation and analysis of the samples to a laboratory. Analysis of samples in the laboratory reveals important information about the reservoir fluid nature. In a laboratory sample, fluids are placed under conditions of pressure and temperature, which simulate reservoir conditions, and various fluid properties, such as bubble point and formation volume factor, are measured. These data are inputs into reservoir models. The properties of the reservoir fluids analyzed in this manner are collectively referred to as PVT — pressure, volume, and temperature properties. Other fluid properties, such as the presence of trace elements like sulphur compounds, radon, hydrogen sulphide (H_2S), and carbon dioxide (CO_2), or the nature of oil for assay purposes, are measured through a variety of other sampling techniques.

The reservoir engineer will specify the requirement for sampling in the test objectives and advise the well test engineer as to the quantity and type of samples required. In subsequent detailed planning, the sampling program will be refined to include details as to quantities of each type of sample and the timing during the test to take them. The sampling program will vary according to the nature of the well and the well fluids. One of the tasks of the well test engineer will be to work with the reservoir engineer and the sampling contractor to design a test in which the samples taken are representative of the reservoir fluid.

In general, samples for PVT lab analysis are either taken at monophasic conditions (i.e., a liquid phase only with all associated gas in solution in the oil) or as recombination samples (oil and gas taken in separate containers and recombined later in the laboratory to reservoir conditions).

Monophasic sampling can occur at any point in the well where conditions of pressure and temperature are such that the well fluid exists in a liquid state only, that is, above bubble point. These conditions often exist near the bottom of the well and occasionally at surface in the high-pressure segment of the surface test equipment. The equipment required to take samples from the bottom of the well is entirely different from the equipment required to take samples at surface. Bottomhole sampling equipment is highly specialized, and if required for the test, planning should include adequate time to allow the sampling services contractor time to locate and prepare the specialized equipment and personnel. Sometimes bottomhole sampling operations require an additional slickline or wireline service to convey the sample tools into the well. Other equipment is also required for pressure control during wireline sampling operations. Apart from the additional equipment and services, wireline-conveyed bottomhole sample operations are lengthy

procedures performed on critical path and are therefore costly. In recent years, alternative bottomhole sampling tools have been developed which are not wireline conveyed. These tools are conveyed in the test string with the downhole tools and are activated from surface with pressure applied to the annulus during the test. This type of tool has the advantage that it does not require additional critical path time to take the samples. However, the quality of the samples cannot be verified until the tool has been retrieved to surface.

Not all well tests require bottomhole sampling. The most common type of samples are surface recombination samples, which are normally taken from the separator. Unlike bottomhole samples taken under monophasic conditions, separator samples are taken as two separate phases, liquid and gas. Oil and gas samples taken simultaneously from the separator into separate containers constitute a paired set of samples. Only paired sets are valid for analysis, as conditions may change between samples taken at different times. Therefore, the procedure for capturing and labeling samples is critical to ensure samples are representative.

The timing of samples is also important, particularly in wells producing close to the bubble point. The drop in pressure in the near wellbore area caused by production into the test string may result in an excessively high Gas to Oil Ratio GOR value. Even after a shut-in period, any subsequent sampling flow period may still have a high GOR. The reservoir engineer must consider when sampling is likely to be most representative and may, for example, elect to sample both early and late in the test to produce comparative samples.

Atmospheric or "dead" oil and water samples are taken from the surface facility for a variety of reasons, for example, to analyze the oil for assay purposes or to design special chemicals that may be required during production such as emulsion or foam breakers.

Apart from samples taken for PVT and assay analysis, other samples are taken to provide information relevant to materials selection and the design of a production facility. Dry gas, for example, contains traces of other elements that can significantly impact the design of a future production facility.

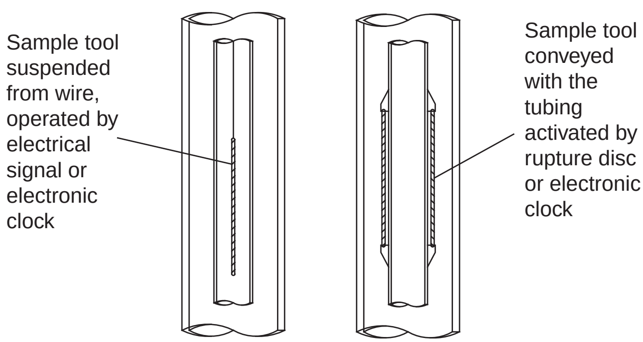


FIGURE 2.12 Bottom Hole Sample Methods

Examples of such elements include hydrogen sulphide (H_2S), carbon dioxide (CO_2), radon, and sulphur compounds. Some of these elements can be measured with simple stain tubes. However, for accurate measurements more sophisticated chemistry is required. This involves special equipment, chemicals, and expertise.

Water recovered during the test is also sampled, usually from the separator. It is important to identify the nature of any water produced in order to distinguish reservoir formation water from brine or brine filtrate.

The sample program should be planned well in advance to ensure that the specialists on site have all the resources necessary to acquire all the samples needed to provide a complete description of the reservoir fluids.

GAUGE SERVICE

The gauge service provides reliable and accurate pressure and temperature well test data that are recorded from as close as possible to the reservoir. In practice, a gauge service company provides the electronic gauges, the carrier, and the expertise to set up, install, and retrieve the data from the gauges after the well test. The contractor provides the acquired data in a report electronically, according to any desired format.

Data acquired in this manner provides important input to a reservoir model. So-called transient drawdown and buildup pressure data reveals information about the reservoir some distance away from the production bore. Such data may reveal detail as to reservoir structure or boundaries, permeability, and skin. The quality of the pressure and temperature data is critical to this analysis, and a great deal of care is taken during planning and during the test to assure this data quality.

Physically, an electronic recording gauge has dimensions similar to that of a broom handle with dimensions of 1.2 to 1.5-in. diameter and a length of about 1 to 1.5 m. A recorder gauge typically comprises a battery and an electronics cartridge, which includes the memory and a sensor.

A measure of the quality of the recorded pressure and temperature data is the degree to which it reflects pressure and temperature changes in the reservoir only and not those induced by the presence of the test string and surface activity. One of the tasks of the well test engineer is to design the test to achieve the highest possible quality data for analysis.

Specific aspects of the test design in relation to downhole pressure and temperature include

- Selection of gauges most suited to the well test.
- Positioning gauges close to the reservoir.
- Downhole shut-in devices located just above the gauge sensor point in order to isolate the effects of the wellbore on the gauges.
- Gauge programming to suit the needs of the reservoir engineer.

- Programmed drawdown and buildup sequence to induce the reservoir responses required.
- Multiple gauges for cross reference and for providing contingency in the event of gauge failure.
- Recording of annulus and seabed data for reference.
- Surface readout to assess gauge data before retrieving the test string.

Types of Gauge

Various types of gauges are available from each contractor. Generally, they fall into two categories based on sensor type: quartz and strain gauges. The strain gauge, being an older design, is based on recording the change in electrical resistance induced by changes in applied pressure to a resistor circuit. Quartz crystal gauges record the changes in frequency on a vibrating crystal element induced by applied pressure. The performance characteristics, accuracy, and resolution for a quartz crystal gauge are generally superior to those for a strain gauge. Quartz crystal gauges are preferred for this reason. For gauges of the same sensor type, specifications such as accuracy, resolution, sensitivity, operating pressure/temperature range, battery life, and memory size may vary from one contractor's gauge to the next. Sometimes specific well test objectives place emphasis on one of these features. For example,

- The temperature range of a gauge is critical in a high temperature well.
- Gauge resolution is most important for transient analysis
- Battery life and memory size are important for extended well tests

Gauges are attached to the test string by means of a gauge carrier. Basically, a gauge carrier is a tube that allows a number of gauges to be secured externally and at the same time ported with a system of seals so that the sensor for each gauge picks up pressure from inside the gauge carrier. The carrier is also supplied with threaded connections on either end so that it may be attached to the test tubing.

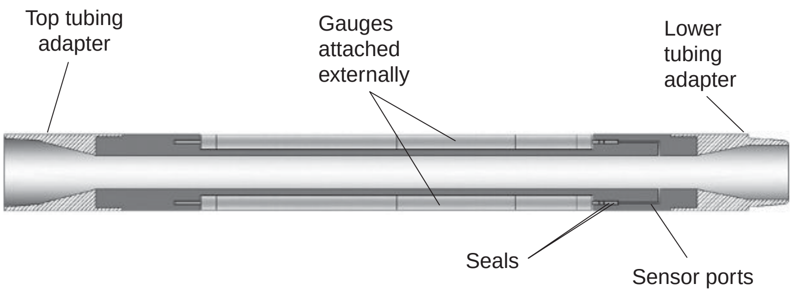


FIGURE 2.13 Gauge Carrier

Features for a typical gauge carrier include:

- Ability to hold several gauges, usually mounted externally around the carrier.
- Full bore through the carrier so as not to restrict the flow of the well.
- Design specifications, tensile and compressive strength compatible with well test tubulars.
- Interchangeable end adapters to allow the gauge carrier to run with a range of different types of tubing.
- Adjustable pressure ports to provide options that permit communication between individual gauges and the internal bore of the gauge carrier, or externally to the annulus.

Gauge carriers are positioned as close as possible to the reservoir to optimize the quality of data recorded. When positioned higher up in the test string, factors of turbulence and friction may impair the validity of the measured data during flow periods, and the effect of hydrostatic pressure in the wellbore may influence the buildup data during shut-in periods. However, for practical reasons it may not be possible to eliminate these effects completely, as other equipment is necessarily positioned below the gauge carrier, thereby creating some separation between the gauge-sensing points and the formation.

Given the value of the data and the cost of acquiring it, and given that in most instances the data cannot be checked until after the test when the test string has been recovered, it is good practice to run several gauges in the gauge carrier for redundancy, in the event of a gauge failure.

During production, pressure and temperature data recorded by the gauges is often noisy owing to the behavior of fluids in the wellbore. Liquid holdup, gas breakout, and turbulence contribute to this noise. Interpretation of gauge data is most often based on buildup data, that is, the pressure response in the reservoir once production has stopped. It makes a significant difference where this shut in occurs. If at surface, it may take some time for conditions in the test string to reach equilibrium so that the data recorded on the gauges is noisy due to this wellbore activity, reservoir fluids continue to flow into the wellbore until an equilibrium pressure has been reached. Movement of fluid in the test string occurs due to gas going into solution as pressure builds up, or as phases separate due to cooling of the wellbore. In order to remove these so-called wellbore storage effects, a downhole shut-in device or tester valve, positioned just above the gauges, facilitates a significant improvement in data quality. A tester valve isolates most of the wellbore from the gauges so that pressure and temperature responses observed on the gauges can be attributed directly to the reservoir and not to activity in the test string.

With high-resolution quartz gauges, it is sometimes useful to install two sets of gauges separated by a joint or stand of tubing. The data retrieved from the two sets of gauges can provide useful gradient data and help identify fluids. This may prove particularly useful if, for any reason, reservoir

hydrocarbons do not flow to surface. Some knowledge of production may be inferred from the changing hydrostatic pressures between the two carriers.

To aid the reservoir engineer in the task of distinguishing reservoir-related data from wellbore effects, a gauge recording annulus data above the packer can be useful. This data is not used for interpretation directly, but can be very helpful in identifying events that might influence reservoir buildup. Annulus pressure changes throughout the test, and pressure is maintained to keep the tester valve open. However, this pressure varies as the driller increases pressure to compensate for cooling, or decreases pressure to compensate for heating. Gauges can also be placed on the seabed to record the effects of tide and ocean temperature, which can also influence the data.

Programming a gauge setup principally involves selecting a delay time and a sample rate. The responsibility for selecting the gauge setup lies with the reservoir engineer. A sample rate should have a sufficiently high frequency to ensure that rapid changes in reservoir conditions are recorded. This is particularly important during the early part of the buildup after the well has shut in. However if the sample rate is set to a very high frequency, there is a danger that the gauge memory may reach its capacity before the test has been completed. This would result in a failure to capture all of the test data. Selecting a delay time such that the gauge only starts recording just prior to the commencement of the test can save a significant amount of memory. It can take anything up to 24 hours to install a test string into a well and to perform all of the necessary commissioning steps before a test can commence.

Prior to mobilizing gauges to the field, the well test engineer should satisfy him- or herself that the gauges are properly calibrated and serviced. An instrument lab calibration certificate should be available for every gauge. On the facility, a further calibration check can be performed when the gauge carrier is pressure-tested on deck.

It is essential that detailed records of the setup used for each gauge are recorded and included in the test report. Considerations for every gauge record are:

- Gauge serial number
- Delay time
- Sample rate
- Other preprogrammed setups if used
- Sensor measuring point depth
- Start time as given by the gauge/PC clock

Any confusion in the above details can lead to a mistake in interpretation of the data. For this reason, as a good quality control check, the well test engineer should witness the status of each gauge and the gauge programming setup and also witness the installation of the gauges into the gauge

carrier prior to its installation in the test string. It is good practice to take a measuring tape and physically measure the distance from the gauge sensor measuring points to a known reference in the test string, for example, the bottom of the gauge carrier.

If there is any question as to the validity of the data recorded on the gauges, or if there is conflicting data from different gauges, then it is a good practice to perform a field calibration check on the gauges to identify possible faults. A more detailed post-test calibration can be performed in the laboratory. It may be possible to "rescue" bad data by reprogramming the gauge with a new set of calibration figures and reapplying this information to the recorded raw data.

WIRELINE SERVICE

The term *wireline* is sometimes used to refer to both electric line and slickline operations. In the context of this book and in an effort to avoid confusion, I use the term *wireline* to refer to electric line services only. Slickline services, which utilize steel piano wire, are discussed in the next section.

Wireline services are operations carried out on a well using an armored cable inside which are a number of electrical conductors. The cable powers a variety of tools and is also used to transmit and receive signals from those tools. An example of just a few of the services performed on wireline include open-hole logging, production logging, bottomhole sampling, setting packers, wireline-conveyed perforating, and depth correlation.

A wireline services contractor provides the equipment, personnel, and support necessary to run a range of specialized tools into the well on wire. A great deal of data is acquired in this manner, and the range of tools available is extensive. In general, wireline operations may be split into two general categories: open-hole and cased-hole services. Open-hole services involve large and sometimes very sophisticated tools conveyed into the wellbore at the end of the drilling phase and before any liner has been run. Open-hole tools are the largest in the suite of tools available from a wireline service and are conveyed on heptacable, steel-braided cable about ½in. in diameter wrapped around a number of electrical conductors that connect to the tools to provide various functions, either powering different components within the tools or transmitting/receiving data between the tools downhole and the computer unit at surface. These tools record and measure electrical resistivity, radioactive background and absorption, and rock properties and can also take samples and perform mini Drill Stem Test DSTs using a combination of packers, pressure sensors, and sampling chambers. The data acquired is plotted against depth, and the output is in the form of a continuous paper or electronic log that plots each of the measures against depth. This operation of acquiring data and plotting it against depth is referred to as logging. A typical logging operation involves lowering the wireline tool(s)

to a depth below the point of interest, with the tools switched on and acquiring data. The winch unit starts to pull the tool upward at a steady pace and at a speed that allows the tool to take data samples without losing resolution.

Cased-hole services are conducted inside casing and often inside tubing. Many of the tools associated with cased-hole operations are smaller than those utilized in open-hole services. The smaller tools are conveyed using a monocable, that is, a steel-braided cable about ¼ in. in diameter, which protects one or sometimes two electrical conductors.

Some of the wireline operations conducted in association with well test operations include cement bond logs to determine liner cement quality, gauge ring and junk baskets to check the condition of the casing, packer setting, and depth correlation. Perforating services are also available on wireline as discussed earlier in this chapter.

Wireline services are present on many rigs to conduct open-hole logging operations at the end of the drilling phase, but they are often not set up to support well test operations, which usually entail some specialized services. In particular, through tubing wireline services require expensive pressure control equipment attached to the test string. These services include depth correlation, production logging, wireline perforations, gauge surveys, and bottomhole sampling.

Through tubing service equipment, including pressure control equipment, is not always off the shelf. The test engineer should review the need for these services with the planning team at an early stage in order to allow the wireline service contractor adequate time to source and mobilize the necessary equipment. Often the conclusion is that the services should be available for contingency only. For example, if the guns fail to fire and the cost of retrieving the test string to rerun TCP cannot be justified, wireline-conveyed guns, though significantly smaller than TCP, are often required as backup. Other contingency services include chemical cutting to release packers or to cut stuck pipe and tubing punches, which are single-shot perforating charges used to establish tubing to annulus communication downhole if, for example, the circulating valve(s) have failed.

One of the most common wireline services performed for a well test is that of depth correlation. Well depths often reference against wireline open-hole logs taken at the end of the drilling phase. Wireline logs measure a number of well parameters such as resistivity, gamma radiation, and other rock properties. The reservoir engineer evaluates this data to determine information about the nature of the formation rock, including the hydrocarbon-bearing sections. Gamma radiation is a naturally occurring radiation. A gamma radiation sensor inside the wireline logging tools measures the varying intensity of this radiation. The data is plotted against depth on a continuous log to produce a unique gamma ray signature for the well.

By installing a small radioactive "pip" tag in the test string above the guns, a gamma ray sensor run on wireline through the test tubing will pick up the background rock gamma radiation together with the "spike" associated with the pip tag located inside a known connection near the bottom of the test string. Thus, the relative position of the pip tag to the formation can be determined with a great deal of accuracy.

The equipment specific to wireline operations includes a logging winch with either one or two cable drums, a tool shack, tool racks with the various logging tools required for the job, and pressure control equipment if required.

The logging winch is located on the MODU positioned so as to readily access the drill floor, preferably in direct line of sight in order to run a cable from the winch directly to the drill floor. The logging unit drives the winch

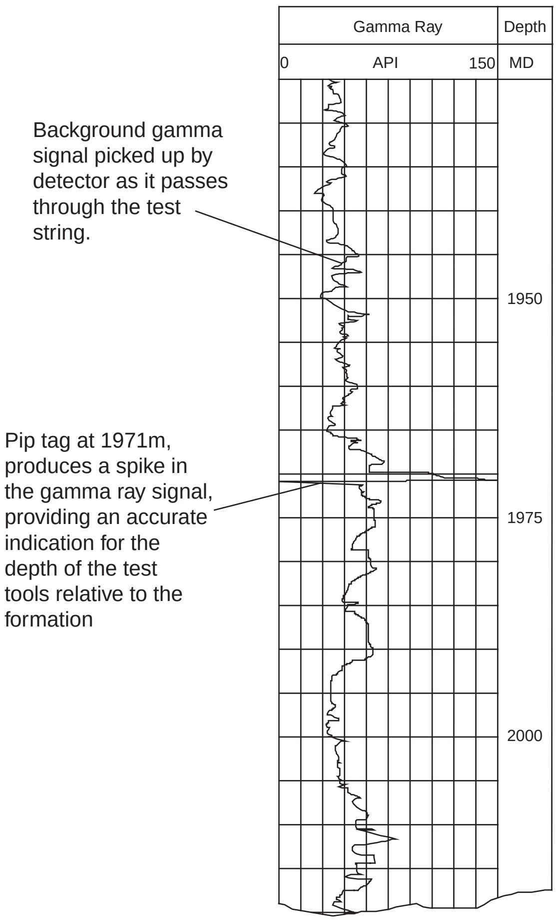


FIGURE 2.14 Pip Tag Depth Correlation

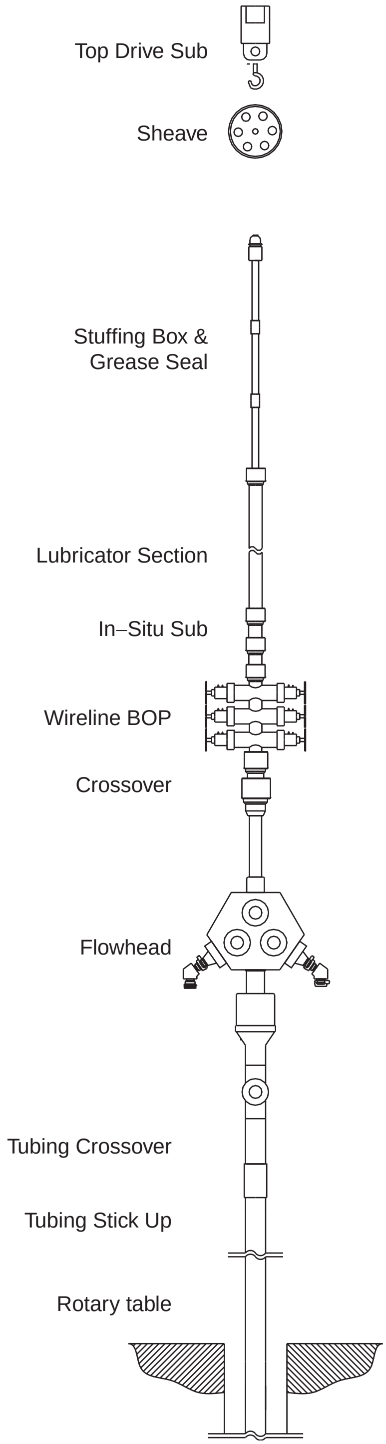
cable and also houses the computers and various modules associated with processing the data transmitted to and from the various logging tools. The test engineer should always be present in the logging unit to witness crtical operations related to the well test such as correlating a packer setting depth. A typical logging unit might only be set up to conduct open-hole logging using a large heptacable. This type of cable is too large for the through tubing operations usually required for a well test, which require a much smaller monoconductor cable. As this type of cable is not automatically supplied with every logging unit, the test engineer should review the availability of the cable and tools necessary for any well test specific service. A typical wireline crew comprises a wireline engineer and a crew of two to three technicians, though this number is often doubled where operations are likely to run over a 12-hour period.

Pressure Control Equipment

As shown in Figure 2.16, the first component in the pressure control equipment is an adapter to the flowhead. Above this is the wireline blowout preventer (BOP), a device that incorporates two or three sets of hydraulic rams that can be activated by the wireline crew to close against the wire and form a pressure seal without actually breaking the wire. The BOP is occasionally required when the primary grease seal fails. Without the BOP, should a leak in the pressure control equipment develop, it would be necessary to cut the wire in order to close a valve in the test string to contain the leak. Situated above the BOPs, the lubricator sections provide the space to install and remove wireline tools, including perforating charges. Above the lubricator sections is the tool catcher. This device is used to hold the wireline toolstring against the top of the lubricator sections during periods when the wire is not in tension, for example, during installation. Above the tool catcher are the grease seal tubes. The clearance inside the tubes between the wire and the tube wall is small. Special grease injected under pressure into the lower part of the tube flows up through the restricted space and returns via another hydraulic line fitted to the outlet. The grease is designed to help seal the wire and lubricate its movement. At the top of the assembly is the pack off, which is a rubber seal that can be energized with hydraulic pressure to seal around the wire in order to stop grease from escaping at the top. Finally, a set of sheave wheels suspended above the pressure control equipment and at the drill floor level direct the wire from the winch unit.

Particular care should be taken to ensure that the correct adapter to the flowhead is supplied, as this is usually an interface between two different contractors. On a floating MODU, the test string is suspended from the derrick using a set of bail arms attached to the flowhead. The test string and the bail arms move relative to the rest of the rig. If pressure control equipment is to be utilized for the test, then adequate space above the flowhead should be made

FIGURE 2.15 Wireline Pressure Control Equipment



available to accommodate pressure control equipment and still support the weight of the test string from the blocks. This entails the use of extended bail arms specially supplied with the test equipment. The well test engineer will work with the wireline contractor to determine the space required between the flowhead and the blocks to rig up the pressure control equipment.

SLICKLINE SERVICE

Slickline services, unlike wireline services, utilize a slick steel wire, sometimes referred to as piano wire, to perform a range of operations through manipulation of the wire using a range of specialist slickline tools.

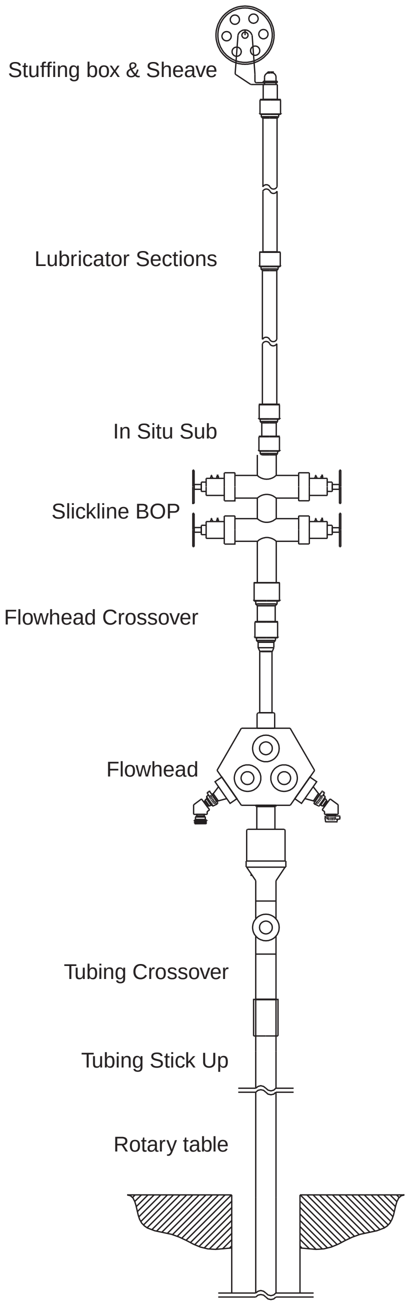
Like wireline, most well test slickline operations take place through tubing with the aid of pressure control equipment installed above the test flowhead.

For normal well test activity, slickline operations occur as part of the well test program or are required as contingency in the event of problems during the test. Programmed slickline services might include bottomhole samples, memory gauge surveys, TCP firing head installation, and TCP gun release. Some contingency or un-programmed services might include TCP firing head retrieval and rerun, drift runs to check tubing clearance, and bailing to remove sand debris from the tubing.

A typical slickline operation, for example, one that performs a gradient survey with a memory gauge, requires a slickline winch unit, a set of pressure control equipment, a standard slickline string, and an adapter to fit a memory gauge to the string.

The winch unit includes the winch with a drum of wire, a power unit, usually diesel driven, and a control cab where the winch operator drives the winch and monitors parameters such as winch speed, depth, and weight. The wire is directed to the pressure control equipment using a set of specially sized wire sheaves. The winch unit is ideally situated to provide a direct line of sight from the winch operator's control cab to the pressure control equipment on the drill floor. The slickline pressure control equipment performs the same function as that for wireline and has many similar components. It comprises a hydraulically controlled BOP fitted with a set of rubber rams that can close to form a pressure tight seal around the wire, an adapter to the flowhead, a set of lubricator sections, long enough to house the tool string, and a stuffing box, which houses a set of seals that permit wire movement up or down while under pressure. The stuffing box is also fitted with an integral wire sheave. A typical tool string comprises a rope socket that clamps the wire and provides an adapter to a standard thread size; a set of weights to help overcome friction through the stuffing box seals; internal well pressure; and the weight of the wire from the winch unit. A set of expandable jars to generate both upward and downward forces for operating various tools or to help dislodge a stuck tool string and an adapter to connect the specific tools are required for the operation at hand.

FIGURE 2.16 Slickline Pressure Control Equipment



To illustrate a typical slickline operation consider a gradient survey, a gauge is attached to the toolstring and placed inside the lubricator section of the pressure control equipment. Pressure in the test string is isolated from the pressure control equipment, with valves closed both subsea and in the flowhead. Once the lubricator is reattached above the BOP with the toolstring and gauge inside, pressure is equalized across the closed valves. This is achieved by pumping fluid into the pressure control equipment using the cement unit. Once equalized, the subsea and flowhead valves are opened, and the gauge and toolstring are free to run into the well under pressure. In order to conduct a gradient survey, the reservoir engineer will specify a range of depths at which the gauge should be stationary, typically working up the hole for better depth control. Once at surface, the subsea and flowhead valves are again closed and pressure is bled off above. The lubricator is disconnected from the BOP, and the gauge is retrieved in order to download the data to a computer.

A typical slickline crew includes a senior slickline supervisor and a crew of one or two technicians, these numbers are doubled where 24-hour coverage is needed.

NITROGEN SERVICE

Nitrogen is often utilized as a cushion fluid in situations where a large underbalance is required to kick off production. Conditions giving rise to this need include low reservoir pressure, combined with low permeability, low GOR fluid, and high skin due to excessive drilling fluid losses. In these cases, the achievable underbalance from diesel or other fluids may be insufficient to start production. Nitrogen is well suited because it is light and inert.

A nitrogen services contractor will provide liquid nitrogen tanks, condenser unit, pumps, and interconnecting pipework and hoses, together with personnel trained to install and operate the system. A typical crew includes a supervisor and one or two technicians per 12 hours of operation.

Liquid nitrogen is shipped in special dual skin vessels fitted with safety devices that vent excess pressure and help to cool the nitrogen and maintain it in liquid form, though some losses do occur and 1 to 2 percent of the tank volume can be lost through the venting system each day. The volume of fluid in the test string that can be displaced by any given amount of liquid nitrogen in a tank depends on the depth, weight, and volume of the fluid to be displaced.

Figure 2.17 illustrates a typical deck setup, a cooling pump initially re-circulates liquid nitrogen back to the tank until all the lines have cooled sufficiently, the nitrogen is then pumped using a large positive displacement pump to the discharge line as a gas

The nitrogen delivery line from the pump unit is connected to the kill side of the flowhead. A downhole circulating valve is opened, and nitrogen is

pumped into the test string. Returns are taken from the annulus to the rig trip tank and pit system.

The availability of nitrogen in sufficient quantities for this purpose varies from one part of the world to the next. In remote locations, this service may not be available, and the well test engineer may have to evaluate alternatives, for example, multiple diesel cushion displacements.

Another application for nitrogen is gas lifting. Instead of pumping nitrogen gas into the test string through the flowhead, nitrogen is pumped through a coil tubing that can be run inside the test tubing to any desired depth. In this manner, nitrogen gas exiting through the bottom of the coil tubing inside the wellbore lightens the fluid column with gas bubbles, which lift the fluid to surface. This method of gas lifting is utilized in situations where a circulating valve may not be low enough inside the well to provide the desired underbalance, or in horizontal wells where coil tubing can travel along the horizontal section and provide a more complete well cleanup.

In relation to the nitrogen service, issues to consider are the effect of liquid nitrogen spills on personnel and equipment and the handling of pressurized gas. A liter of liquid nitrogen expands to 700 liters of gas at atmospheric conditions. Because it is heavier than air, it accumulates in low-lying areas and will exclude air, creating a dangerous environment for personnel. Consider the location of nitrogen equipment in relation to spaces below it, are there access hatches? Or air intakes that may provide a path for nitrogen to accumulate below decks. Liquid nitrogen that comes in contact with the deck as the result of a leak can cause material embrittlement and cracking. In order to protect the deck, barrier material such as plywood and tarpaulin should be laid

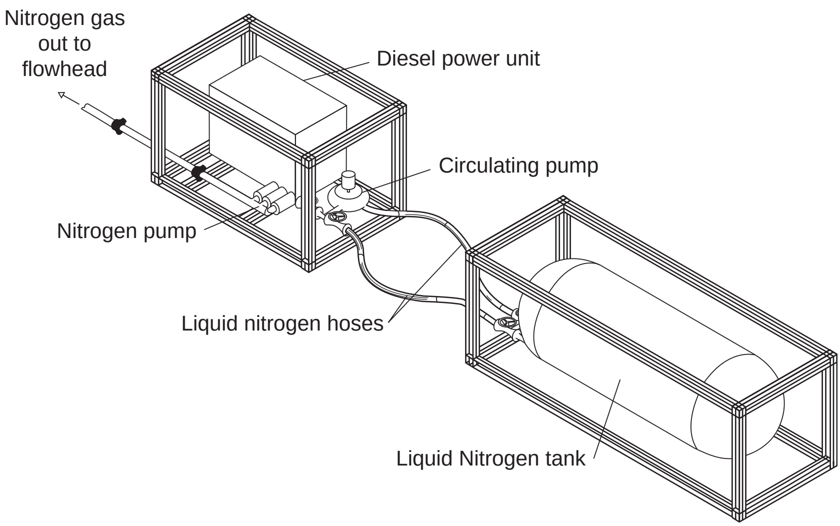


FIGURE 2.17 Nitrogen Equipment

so as to cover the area where the tank will be positioned. Running water may also be used if it is available in sufficient quantities, although on offshore facilities covering the deck with seawater is less desirable than utilizing tarpaulin and plywood. Personnel contacting ice-covered pipework can experience injuries to the skin not unlike a burn. For this reason, access to areas where nitrogen equipment is in use is restricted, and the nitrogen service crew will wear appropriate personal protective clothing when working with this equipment.

COIL TUBING SERVICE

Coil tubing, as its name implies, is a service that utilizes a long, continuous coil of tubing to run inside a test string in much the same way as wireline. Common coil tubing sizes are 1.25 in., 1.75 in., and 2.25 in. in diameter; planning should consider the size of coil and any restrictions in the test tubing string. Coil tubing may be used much as slickline and wireline are used to convey specialized tools into the well but with the added advantages that the coil is capable of generating much greater pulling forces than wire, and is also capable of pushing tools to the bottom. In addition to mechanical tools, it is possible to obtain coil tubing with electrical conductor cable threaded inside. This gives it the ability to perform services that are normally only available with wireline. Coil tubing is also ideally suited to work in horizontal wells to clean out fluid that is not removed during normal well cleanup techniques. Other services available include acid washing, horizontal logging, perforating. and gas lifting.

As shown in Figure 2.18, coil tubing equipment comprises a winch unit with a drum of coil tubing, a control cabin, diesel powered hydraulics, an injector head, a BOP, and a lifting frame specifically for use on offshore floating rigs. The winch is positioned on deck in line with access to the drill floor, usually at the end of the catwalk and pointed toward the vee door. The control cabin is positioned close by so that the operator can observe the coil. The injector head and BOP are mounted on top of the test string above the flowhead. On a floating rig, the flowhead is rigged up using the lifting frame, which provides a platform between the flowhead and the top drive in order to facilitate the BOP and injector head installation. A range of tools can be fitted to the end of the coil before the injector head is made up to the BOP.

Coil tubing is the least frequently used service in well testing; if required, steps to secure its availability should be taken early in planning. A typical crew comprises a coil tubing supervisor and two or three technicians per 12 hours of operation. Rig interfaces for the coil tubing should be assessed by the coil tubing supervisor. Issues to consider are the clearance at the vee door for the coil to reach from the deck to the injector head situated perhaps 15 m above the drill floor level. The location of equipment on deck should

be agreed upon with rig management, and the weight of the equipment should be assessed for that area. Interfaces with other services should also be considered. For example, the subsea service shall require a subsea tree capable of cutting coil tubing in an emergency. The coil tubing service company should work with the well test engineer to develop the procedures governing this operation.

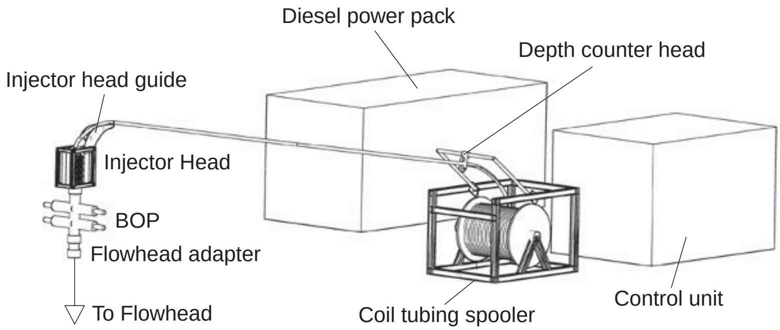


FIGURE 2.18 Coil Tubing Set Up

Chapter | three

Well Test Description

CHAPTER CONTENTS

The object of this book is to describe a well test planning process, and in order to do so it is necessary to describe the subject of that planning: the well test equipment and the well test process. This chapter examines the main components of well test equipment and some of the procedures associated with each. In particular, the section on separation contrasts the procedures for handling oil and gas. As might be imagined from the diverse range of environmental variables and the variety of services involved, not all well tests are identical. This chapter therefore concludes with a discussion of specific issues that significantly influence the test design and provide challenges for planning and execution.

WELL TEST EQUIPMENT

Well test equipment performs one or both of two functions: it controls well fluid, or it measures it. The schematic in Figure 2.10 illustrates a typical setup showing the main equipment components, this installation is represented more simply in the process flow diagram in Figure 3.1

Flowhead

The flowhead is a manifold installed at the top of the test string and performs several control functions. It directs produced fluid to the well test equipment

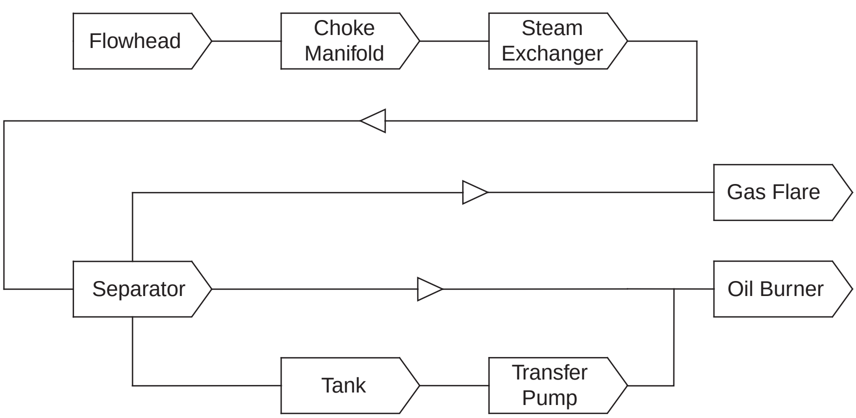


FIGURE 3.1 Test Equipment Process Flow Diagram

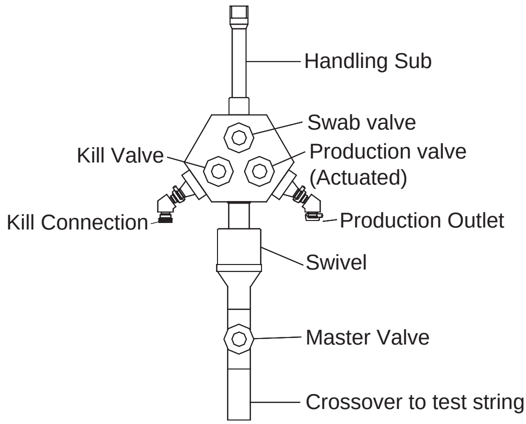


FIGURE 3.2 Flowhead Schematic

through a production valve, it provides a facility for introducing fluids into the test string through the kill valve, and it gives access to the test string for special tools, conveyed on wire or coil tubing through the swab valve. A swivel located below the block, which houses the above valves, simplifies installation, and an additional valve located just below the swivel provides a means to isolate the swivel and valve block if required.

The reference standard for flowheads is API Spec 6A Specification for Wellhead and Christmas Tree Equipment.

Installation of a flowhead requires careful supervision; a toolbox talk that reviews the installation procedure and the potential hazards always precedes this operation. The flowhead is an awkward lift; during transfer from a crane to the elevator blocks, it is top heavy and has the potential to flip over. On offshore floating facilities, a tubing joint attached to the flowhead further complicates the procedure. This additional tubing joint facilitates pressure testing and commissioning the test string prior to land off and setting the packer.

As shown in Figure 3.3, a floating rig rises and falls with the motion of the sea along with the partially installed test string hanging in the slips. The land-off point in the test string must remain well above the wellhead land-off point on the seabed in order to avoid impact damage because of the motion of the rig. After attaching the flowhead and tubing joint assembly and completing the installation and pressure test procedures, the test string can land out using the rig compensators, which control the land off descent to avoid excessive impact at the wellhead.

The production wing valve on a flowhead uses a hydraulic actuator that is usually connected to a remote emergency shutdown system (ESD). This valve is a normally closed design for safety reasons. Other valves on the flowhead may be manual or hydraulic depending on the design. Manual valves require personnel to work at heights for operation, on floating rigs,

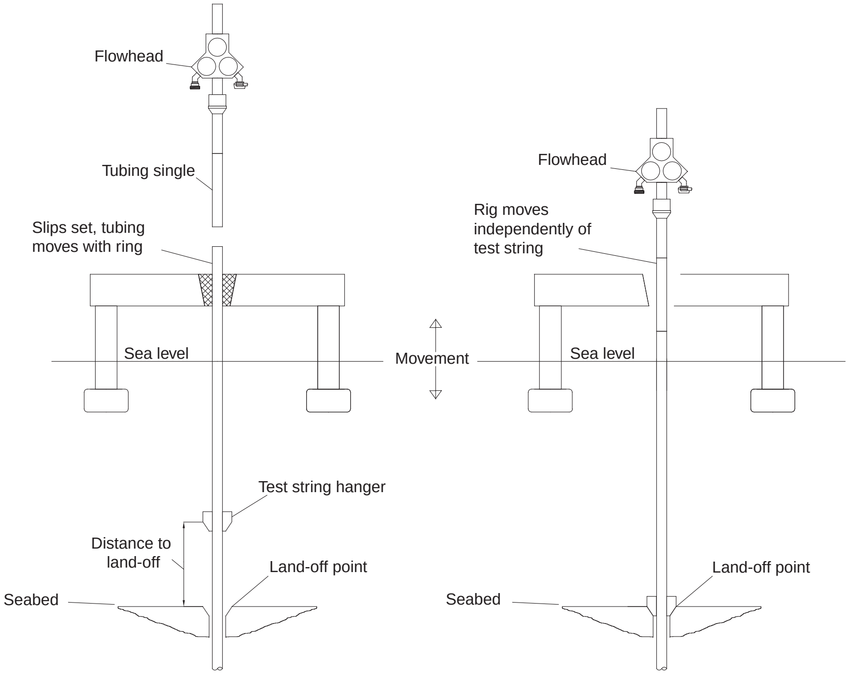


FIGURE 3.3 Flowhead Installation

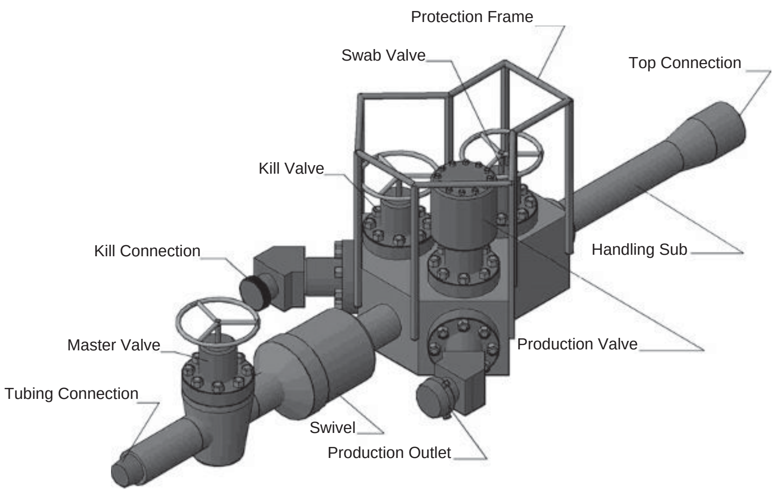


FIGURE 3.4 A Typical Flowhead

this can be as much as 10 m above the rig floor, and the flowhead may be in motion as the rig moves relative to the flowhead. These operations require trained and competent personnel working under appropriate safety management systems.

High-Pressure Flexible Flow Line

Some well test procedures, such as packer setting and unsetting, require flowhead manipulation with surface pipework connected. This would not be possible with the flowhead attached to the test equipment through ridged pipework. On floating offshore rigs, the flowhead moves continuously relative to the rig pipework. For these reasons, high-pressure flexible hoses connect the flowhead to production and kill standpipes.

These hoses use a combination of high-pressure plastic compounds reinforced with layers of steel braiding. The mix of compounds and reinforcing material varies according to manufacturer. Planning for the use of such hoses requires confirmation of the material resistance to corrosive fluids such as H_2S and CO_2, and the maximum fluid velocity permitted through the hose liner are within the manufacturer's specifications. Applicable reference standards are API Spec 16C Specification for Choke and Kill Systems and NACE MR 01 75.

A single hose comprises end connections, with fittings selected to interconnect with rig pipework. Terminations bind and seal the hose layers at each end, and the hose itself makes up the bulk of the length between the terminations. A lifting clamp provided at both ends assists handling. The handling of high-pressure hoses is awkward due to the combination of length and weight. A crane lifts the hose at one end, ideally so that the entire hose suspends vertically above the ground; an air tugger connects to the lower end at the drill floor. As the tugger lifts the lower end to the flowhead connection point, the crane hook lowers the other end so that the hose hangs in a U-shape, thereby making it easier to handle. After the flowhead end is connected and secured, the crane end is transferred to an air tugger and then made up to the standpipe.

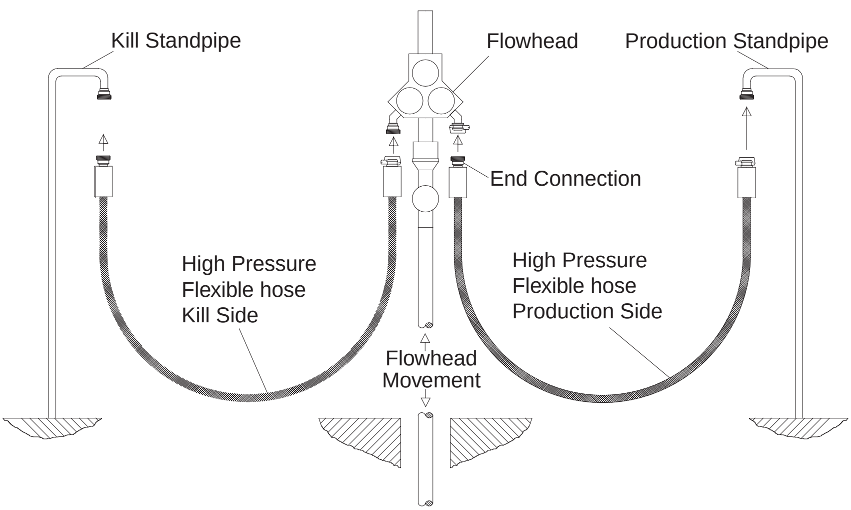


FIGURE 3.5 HP Flexible Hose Configuration

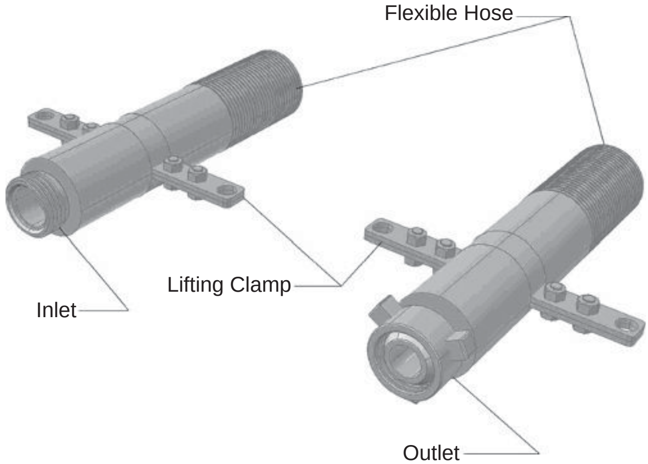


FIGURE 3.6 HP Hose End Fittings

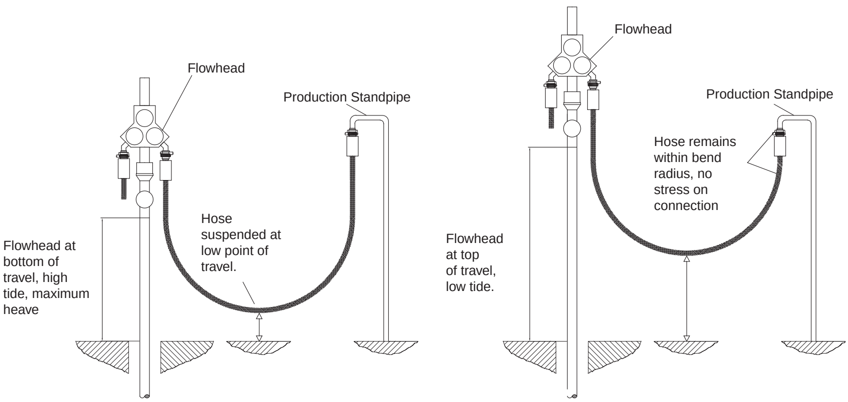


FIGURE 3.7 HP Flexible hose movement after land-off

Every flexible hose of this nature has a minimum bend radius, which must not exceed the manufacturer's recommendation. The well test engineer must ensure that the flowhead stick up is adequate on a floating rig, so that the hose remains suspended between the flowhead and the standpipe with minimal or little contact to the ground. Any movement in the hose as a result of the flowhead manipulation or rig motion is restricted to the midsection of the hose and not the end fittings, where excessive movement under pressure may cause seal failure or damage the hose termination.

Choke Manifold

Well test choke manifold controls fluid pressure using a combination of valves and flow restrictions. Figure 3.8 shows a typical choke manifold configuration.

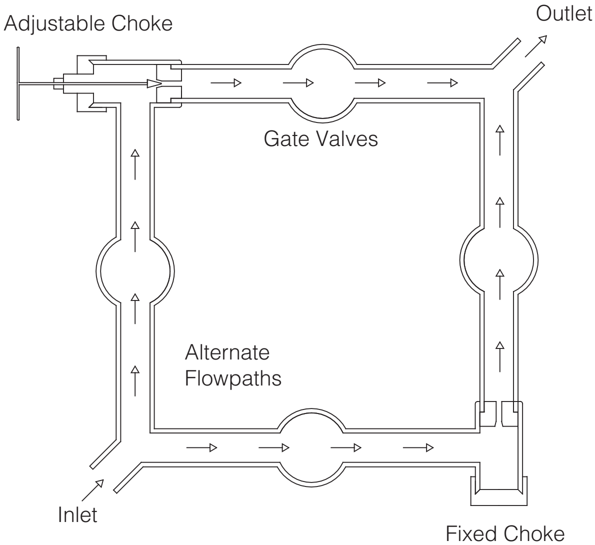


FIGURE 3.8 Choke Manifold Schematic

There are two flow paths through the choke manifold, one through an adjustable choke and the other through a fixed choke.

Each choke restriction has isolation valves upstream and downstream, and in some cases, a double valve on either side is required to provide dual barriers when accessing the choke. The design and manufacture of choke manifolds references API Spec 6A Specification for Wellhead and Christmas Tree Equipment.

The adjustable choke has a cone-shaped plug made of a hardened material such as tungsten carbide and a corresponding seat. Turning a threaded shaft adjusts the cone position to increase or decrease the gap between the cone and the seat, thereby providing an adjustable flow path size. During the cleanup or when changing chokes, the adjustable choke facilitates variable control of the flow.

The fixed choke is useful for stable flow conditions. It consists of a solid metal insert with bore of known size coated with tungsten carbide to provide erosion resistance. Every choke manifold comes with a range of fixed chokes to suit a variety of flow conditions. The flow through the fixed choke is less turbulent, and the restriction size is known with greater accuracy than that of the adjustable, the fixed choke is also less prone to plugging with debris. Access to each choke is necessary in order to change the restriction size or to perform routine maintenance, for example, to remove debris. Assorted fittings on the choke body provide for pressure and temperature sensors and sample access points.

It is at the choke manifold that some of the most critical test operations occur. The choke manifold regulates fluid production through the adjustable choke as conditions change during the cleanup. This protects downstream

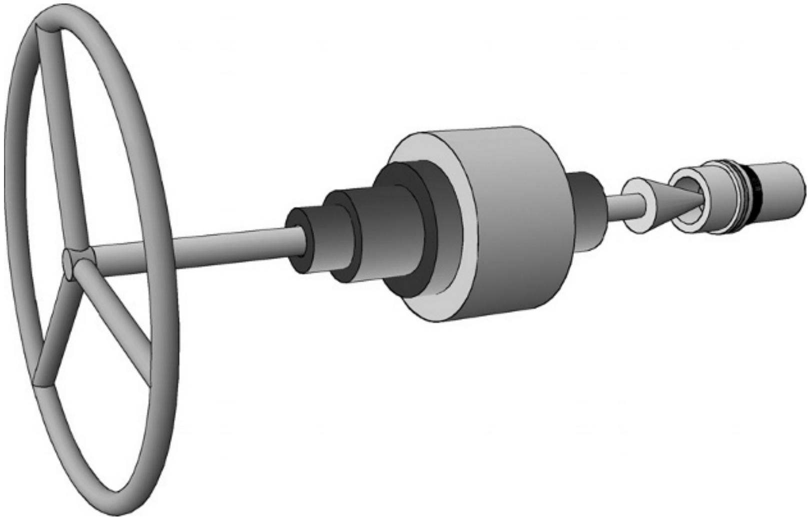


FIGURE 3.9 Adjustable choke and seat

equipment from excessive pressure. Continuous close monitoring is essential during the early cleanup as fluids and conditions change rapidly; for example, a change in fluid phases from liquid to gas may require adjustment of the choke setting to limit pressure downstream. During the main flow, adjustments at the choke manifold involve changing choke sizes to increase or decrease production from the well according to the program.

Choke changes require set procedures in order to prevent unplanned disturbances to the flow, such as accidental well closure. Consider a well producing through a fixed choke, the procedure to switch to a larger choke is as follows. This procedure requires two operators; each controlling one set of valves, with the well flowing through the fixed choke on one side, the adjustable choke on the opposite side is set to the same size as the fixed choke and the downstream valve opened in preparation. An operator gradually closes the upstream valve on the fixed side whilst at the same time the other operator gradually opens the upstream valve on the adjustable side. The operators monitor the pressure upstream and downstream to regulate the changeover in order to maintain constant flowing conditions, afterwards, it is possible to increase or decrease the adjustable choke to the desired new setting. An operator closes the downstream valve on the fixed side and opens a needle valve in the fixed choke chamber to vent the trapped pressure between the upstream and downstream valves to atmosphere, removing a cover permits access to change the fixed choke. The operators repeat the above procedure to switch from the adjustable choke to the new fixed choke.

Steam Exchanger

The purpose of a steam exchanger is to increase the temperature of the produced fluids in order to improve handling. Figure 3.10 illustrates a basic steam exchanger. The main components include a manifold to direct fluid through the steam exchanger or to bypass it, a pipe coil to contain well fluids through the steam exchanger, and a steam jacket to circulate saturated steam around the coils in order to heat the well fluids. Other components include jacket lagging to provide heat insulation. Relief valves protect the low-pressure steam jacket in the event of a leak in the high-pressure coils. A temperature control valve regulates the flow of steam into the jacket, and a condensate trap fitted to the outlet of the steam jacket maintains steam inside the jacket and takes condensed water back to a remote boiler.

The steam exchanger operates between about 90 and 170 Celsius. The boiler generates steam with a diesel-fired furnace; for this reason, it is remote from the well test equipment. Steam from the boiler travels inside steam-rated hoses or pipework to and from the steam exchanger. As the hoses transporting the steam become hot, there is potential for injury to personnel through contact with the hot hoses and potential for damage to the hoses owing to the movement of other equipment on deck or on the lease. Routing the hose away from walkways and work areas and identifying the hose with barrier tape are two simple controls to reduce the hazards associated with this hose. In some installations, lagging the hoses provides additional protection.

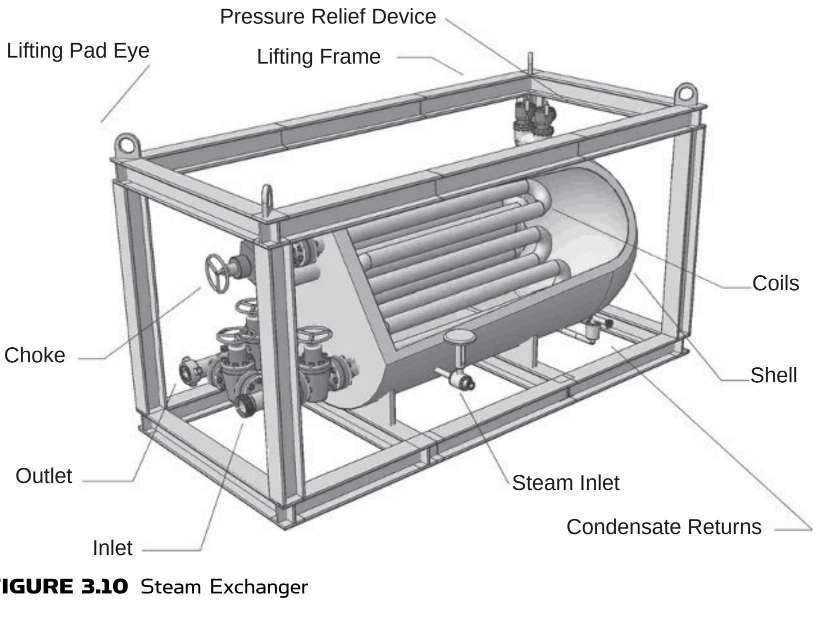


FIGURE 3.10 Steam Exchanger

A choke fitted to the coils of a steam exchanger provides additional control of the well fluid. During a gas well test, hydrates may form, particularly when producing through small choke sizes, as the temperature of the gas drops significantly because of expansion across the choke—the so-called Joules-Thomson effect. The drop in temperature may trigger the onset of hydrate formation or simply cool the well fluids to a level below the specified working temperature for the well test equipment. The velocity of the gas, combined with the relatively poor heat transfer to gas inside the steam exchanger, may result in an inability to elevate the temperature of the gas sufficiently.

A secondary choke midway inside the coils of the steam exchanger reduces the severity of the temperature drop across the choke manifold, thereby dropping the pressure in stages and giving the added benefit that the pressure drop occurs inside the hot steam exchanger. The fluid velocity inside the coils upstream of the steam exchanger choke also drops, improving heat transfer efficiency within that section of the coils.

Relevant standard references for the steam exchanger include ISO 13703 Design and installation of piping systems on offshore platforms or API RP 14E Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, and ASME B31.3.

In certain applications, the steam exchanger can be utilized to cool excessively hot well fluids. Instead of circulating steam, the jacket is water filled and circulated as required to cool well fluid temperatures. To a lesser extent, adjustments in the separator pressure may provide a degree of temperature control.

Separator and Separation

The purpose of a test separator is to separate fluids for metering and sampling. This type of separator operates manually in order to facilitate adjustment in response to a wide range of flowing conditions. This is in contrast to a production separator, which separates fluids for processing purposes and operates automatically to suit a particular set of production conditions.

There are several types of test separator, but all of them utilize differences in fluid density to achieve separation. Because of the vessel size, fluid velocity drops as it enters a separator; the efficiency of fluid separation relates directly to the time it spends inside the vessel, the retention time. Inside, the heaviest fluid, water, falls to the bottom of the vessel. Oil, being lighter, sits in a layer on top of the water. In order to separate these two liquids inside the vessel, a weir divides the bottom of the vessel into two compartments. As the liquid level rises in the first compartment, oil, sitting on top of the water, passes over the weir into the second compartment. Control of the liquid level by the operator ensures that the water level never rises above the top of the weir and that oil remains uncontaminated in the second compartment. Gas exits the vessel from an outlet at the top of the vessel. Apart from the size of the vessel and the retention time, other devices inside the vessel aid separation. Baffle plates at the inlet absorb the kinetic impact of the mixed fluid and promote liquid dropout. Coalescing plates provide a large

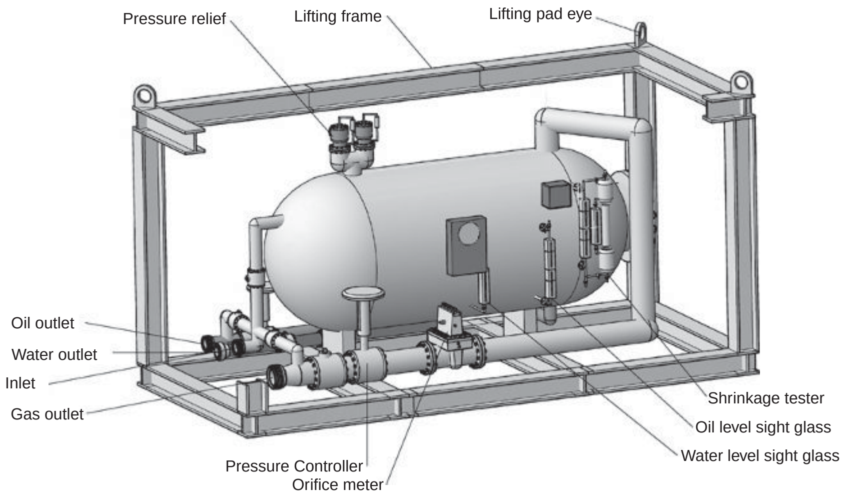


FIGURE 3.11 Separator schematic

surface area on which oil droplets suspended in the gas phase will coalesce into larger droplets and fall into the lower part of the vessel. A demister or fine mesh fixed just before the gas outlet provides a surface for fine droplets remaining in the gas to coalesce and drop out. Sight glasses fitted to the side of the vessel indicate the level of liquid in each compartment. These levels are controlled using automatic valves that open or close to retain fluid inside each compartment or open to increase production and drop the level. The valves use floats to sense the liquid level. The gas discharge valve regulates pressure inside the vessel; this automatically opens to drop pressure or closes to raise it. Some pressure inside the vessel is necessary in order for the separator to operate efficiently. At low pressures, the potential to flood the vessel due to a sudden loss of pressure is greater; pressure is required to drive the liquid from the separator to the downstream components of the test equipment. Low gas to oil ratio (GOR) oil with a corresponding low wellhead pressure may result in a low separator operating pressure. Planning should consider steps to avoid the risk of separator flooding and contingency plans in the event such flooding does occur. For example, using a nitrogen supply to create a gas cap and to operate the separator with the gas discharge closed, one can alternatively consider a liquid knockout vessel fitted to the gas discharge line to provide secondary separation and early warning of liquid carryover.

Burners

After sampling and flow measurements, it only remains to dispose of the well fluids. It is generally neither practical nor economical to handle and store hydrocarbons produced during an exploration well test. The logistics involved would entail considerable double handling and cost. Facilities would be required to store the fluids and then transport them whether by road or by sea to a processing plant where the fluids would need further refining for use.

Burners provide a more practical means of fluid disposal at the well site. In order to burn oil effectively, it is necessary to atomize the liquid into a fine spray of droplets. Pressure of the liquid in the oil line combined with compressed air at the nozzle outlet provides the energy necessary for atomization.

There are a number of ways to control the pressure of the oil traveling to the burner. Adjustment of the choke manifold regulates pressure from the wellhead; well fluids from the choke may produce directly to the burner, for example, during the cleanup, with the separator bypassed. During separation, adjustment of pressure in the vessel with the gas discharge valve controls the pressure of the oil in the discharge line to the burner.

When producing to a tank, liquid inside the tank is at atmospheric pressure. In order to dispose of this liquid, a transfer pump is required to deliver the fluid to the burner at a pressure sufficient to achieve atomization. Heavy oil and/or high volumes of oil require larger capacity pumps to provide the energy needed. Smaller pumps, such as air-driven pumps, are adequate to handle lighter oils and condensates. This is because lighter fluids have lower viscosities and are more volatile, and therefore require less energy to atomize and ignite.

The type of burner, the type of pump, and the number of compressors required to achieve an effective burn vary according to the expected oil type and rate. For crude oil production rates above about 5,000 bopd, as many as six high-capacity compressors may be required to achieve an effective burn. This adds to cost and logistics particularly offshore; six compressors occupy a significant amount of deck space. The flaring of oil generates a significant amount of heat radiation and a consequent fire hazard. Flaring also introduces an environmental hazard should the flame fail for any reason. Planning must consider these issues to ensure adequate control of the hazards.

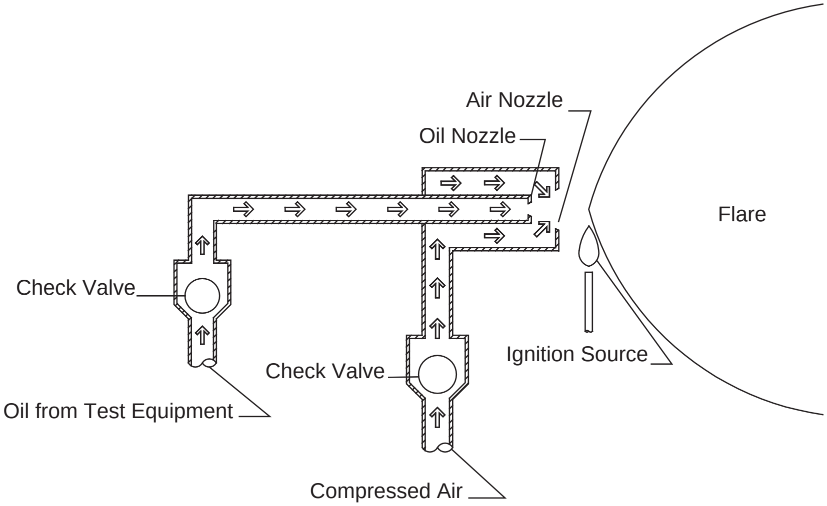


FIGURE 3.12 Burner Nozzle

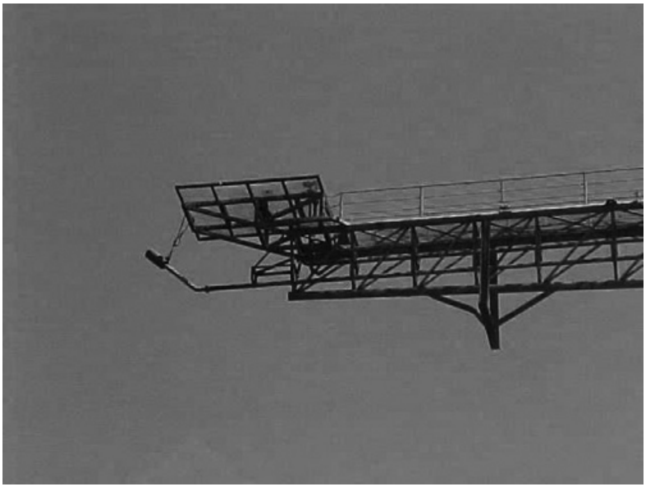


FIGURE 3.13 Gas Flare

Disposal of Gas

Gas exits the separator directly to a gas flare situated in close proximity below the oil burner. The flare from the oil burner ignites the gas flare, doing away with the need for a separate ignition system. Intermediate processing of the gas is generally not required between the separator and the gas flare, but in cases where liquid carryover is anticipated, a knockout vessel situated in the gas discharge can be used. High gas production rates produce high noise levels, with a potential for hearing damage to personnel. This hazard will receive attention during planning, with some thought given to the equipment layout, personnel hearing protection, and communication issues. (See the sections on heat and noise later in this chapter.)

OIL AND GAS MEASUREMENTS

Oil Measurements

In order to allow valid comparisons between wells producing at different rates, production measurements for oil are made at industry standard reference conditions of 101.56 KPa and 15.6 Celsius (14.73 psi and 60 Fahrenheit), sometimes referred to as standard conditions or stock tank conditions.

Readings taken directly from devices fitted to a separator are at separator conditions; adjustments are necessary in order to convert measurements at separator conditions to standard conditions.

Separator Conditions

Measurement of oil production in a separator is typically done with a volumetric metering device fitted to the oil discharge line. Fluid passing through the

device spins a paddle or turbine, which. in turn, spins a mechanical counter. The counter displays fluid volume directly. These meters require calibration before every test since there are losses with slippage, bypass of the paddle/turbine, and frictional losses in the bearings and mechanics of the counter. The calibration factor C applies to every reading taken from the separator.

In order to adjust the readings from separator conditions to standard conditions, additional adjustments are required, a temperature adjustment given as k and the volume adjustment for pressure or shrinkage given as (1-SHR). The equation for volumes at standard conditions is as follows

$$V_{\text{Standard}} = V_{\text{meter}} \times \mathrm{C}_{\text{meter}} \times k \times (1\text{-SHR})$$

Temperature Correction *k*

The temperature correction to standard conditions results in a factor k, which is a volume correction. The standard ASTM D1250 Guide for Use of the Petroleum Measurement Tables, provides the two charts utilized to determine temperature correction

- Specific Gravity Reduction to 60 Fahrenheit
- k Factor for Reducing Oil Volume to 60 Fahrenheit

Shrinkage Correction (1-SHR)

Under separator conditions, some gas remains saturated in the oil, causing it to occupy a larger volume. Shrinkage is simply the difference in volume of a mass of oil at separator conditions compared to the same mass of oil at standard conditions.

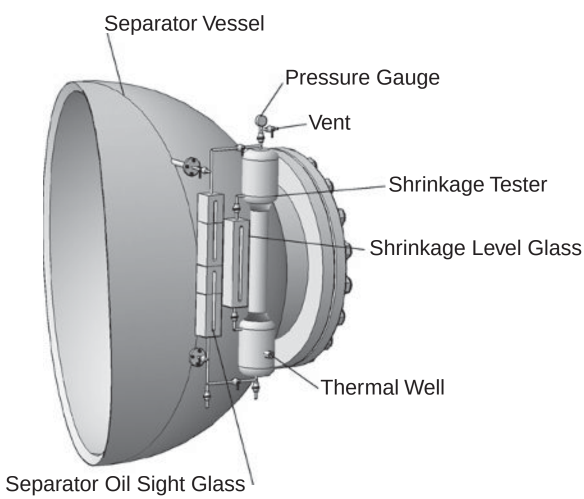


FIGURE 3.14 Shrinkage Tester

Three common methods are available to determine shrinkage. The most accurate method uses a shrinkage tester. A sample is transferred from the separator vessel into a calibrated container at separator conditions.

Once the measured volume has been transferred, the sample container is isolated from the separator and the pressure inside is vented slowly so as not to flash off any liquid, gradually, the pressure inside drops to ambient conditions. After the gas in solution has vented, a graduated scale indicates the percentage shrinkage. A temperature correction *k* applied to the sample provides the shrinkage factor at standard conditions.

Alternative Method for Measuring Shrinkage Factor

During production, oil from the separator is diverted to the tank, recording both the tank volume and the corresponding separator meter volume at the start and end of the transfer. The oil in the tank is left untouched for a period to allow entrained gas to vent off. When further volume reduction occurs, the final tank volume and temperature are recorded.

A volume temperature correction applies to the remaining volume; this corrected volume divided by the volume measured at the separator meter for the transfer provides a combined meter and shrinkage factor. Using this method, the meter calibration on the separator together with the shrinkage factor are set to one, since the calibration factor includes both of these figures.

A third method, based on calculated shrinkage, is also available using Katz methods. These alternative methods to determine shrinkage provide a check on the validity of the shrinkage tester measurement.

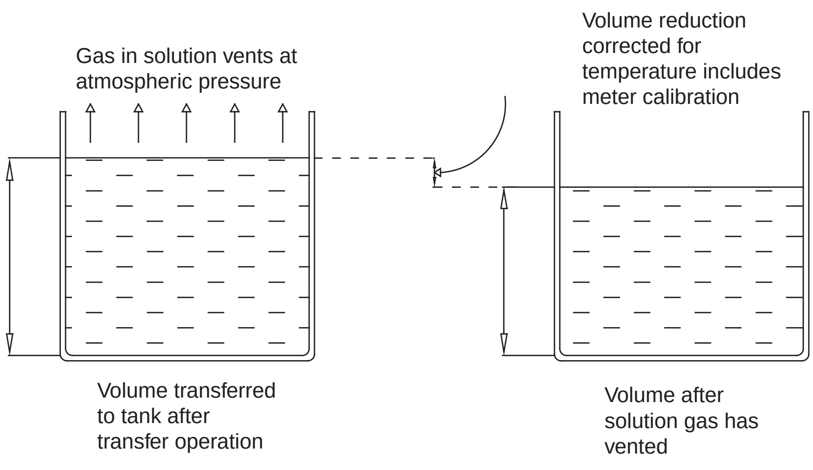


FIGURE 3.15 Shrinkage measurement by tank

Measurement of Oil Gravity

A hydrometer floating inside a sample of oil taken from the separator is a simple device for measuring oil gravity or density. A temperature correction applies to the measurement in order to convert this measurement to standard conditions.

Hydrometer scales can read specific gravity (SG) or degrees API. The relationship between these two units is as follows

$$\text{API gravity} = (141.5/\text{SG}) - 131.5$$

Base Sediment and Water (BSW)

The term *BSW* refers to measurement of the volume of contaminants in the oil, measured from a sample taken from the produced fluids prior to separation, usually at the choke manifold or separator inlet. An operator will take the sample from one of several needle valve sample ports into a graduated glass container, typically 100 ml, and centrifuge to separate the fluid components. The graduations on the tube indicate the percentage BSW, and the measurement is recorded on a data reading sheet (see Table 3.1). Contaminants might include drilling fluid residue, formation water, sand fines, and pipe dope.

The volume of contaminants represented by the percentage BSW measurement reduces the volume of oil measured by the meter at the separator. For instance, if the oil production measured at the meter is 2,000 bopd and the measured BSW is 5 percent, the net meter reading will be 1,900 bopd, expressed as follows

$$V \times (1\text{-BSW})$$

where V = separator oil production measured by the meter

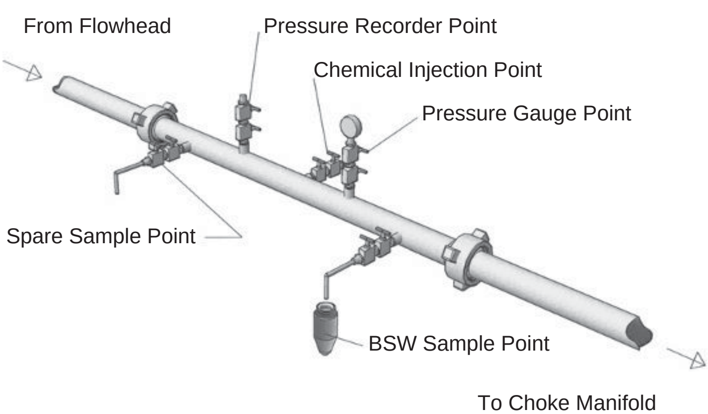


FIGURE 3.16 Instrumentation dataheader

New Technology Liquid Metering Devices

Mass flow meters such as the Coriolis meter provide a more sophisticated metering device. Sometimes configured in a distinctive U-tube shape, an internal tube is set oscillating using an electric current supplied to coils at either end of the tube. The flow of liquid through the tube sets up a twisting force on the inner tube due to the naturally occurring Coriolis Effect. Sensors fitted along the length of the tube detect and measure the twisting force, which is a function of the mass flow rate; the processed data provides production and fluid density data.

Data Recording

Recording of production data occurs regularly and as frequently as practicable during each flow period to provide confidence in its reliability. Table 3.1 illustrates a typical data sampling frequency for a well test.

Gas Metering

Metering of the gas phase takes place in the gas discharge using an orifice meter. This device provides a flow rate measurement based on the principle that gas traveling through an orifice restriction creates a pressure differential across the orifice as a result of the increase in velocity of the gas. As flow rate increases, so, too, does the velocity of the gas and therefore the pressure differential.

AGA report number 3 and API Manual of Petroleum Measurement Standards, Chapter 14, Section 3, are common references for gas metering through well test separators using orifice meters.

Table 3.1 Manual Data Sampling Frequency

Description	Frequency	Location
Pressure	15 mins	Choke Manifold & Separator
Temperature	15 mins	Choke Manifold & Separator
H2S	15 mins initially, 1 hour stabilised	Choke Manifold
CO2	15 mins initially, 1 hour stabilised	Choke Manifold
Mercaptan	30 mins initially, 2 hour stabilised	Choke Manifold
Oil Readings	15 mins	Separator
Gas Readings	15 mins	Separator
Gravity Measurements	30 mins	Separator
BSW	15 mins initially, 1 hour stabilised	Choke Manifold
Shrinkage	2 hours	Separator
Tank Meter Factor	Per flow period	Separator/Tank

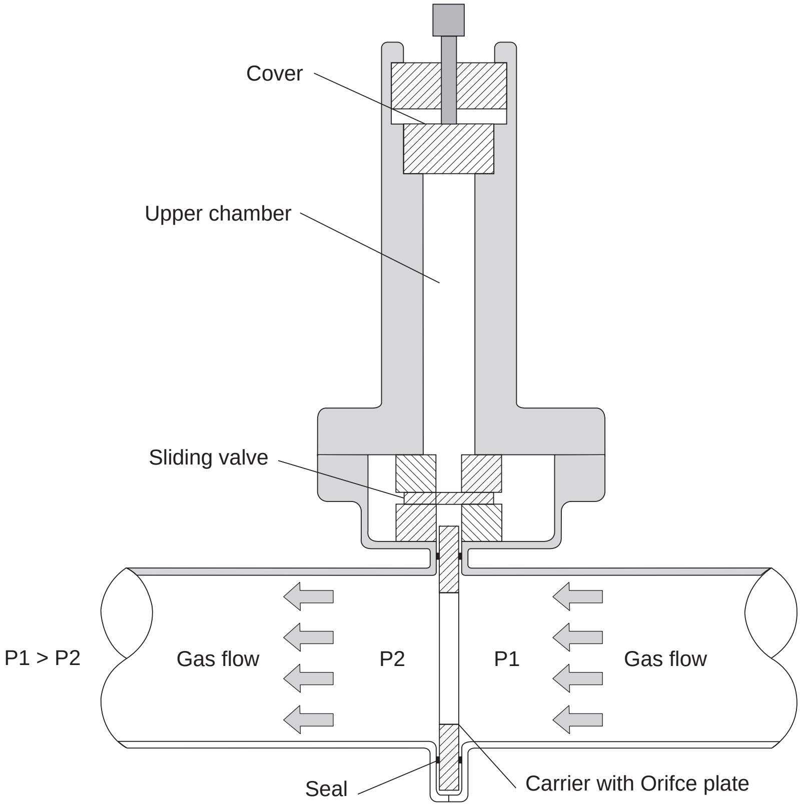


FIGURE 3.17 Orifice meter

The orifice meter requires little calibration. However; the orifice plate size and the condition of the seal for the plate are important and should be included for inspection as quality checks by the well test engineer. The recording device, mechanical or digital, records the differential pressure across the orifice plate; the static pressure upstream or downstream of the orifice plate depends on the specific calculation used and the temperature of the gas. This device requires periodic calibration, usually before every test. The well test engineer retains copies of this calibration for quality assurance purposes.

During production, liquid carryover into the gas discharge line will affect the gas measurement. Close monitoring of the separator level and periodic sampling of the gas in the discharge line take place to ensure that liquid carryover does not occur. Sudden changes in trend on any of the recorded parameters alert the well test crew to possible problems.

Measurement of Gas Gravity

A device known as a Ranarex gravitometer is by far the most commonly used device for field measurement of gas gravity. Two opposing impellers are connected to the same deflection needle; one impeller is supplied with air

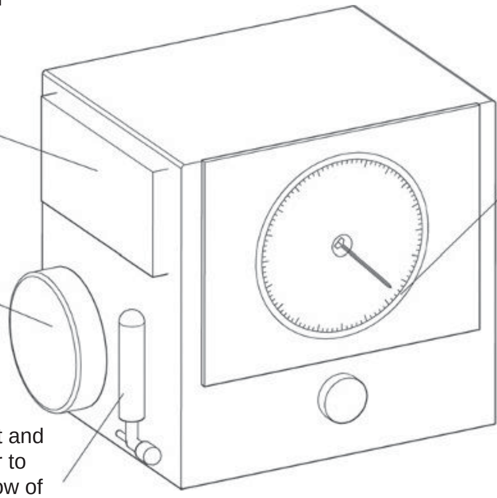


FIGURE 3.18 Ranaraex gas gravitometer

and the other with a sample of gas taken from the gas discharge of the separator using a bladder or pressurized sample bottle. The torque produced by each impeller is a function of the mass of gas striking it. The difference in masses between air and gas results in a net torque that produces a deflection in the needle. The needle points to a scale on the front of the device calibrated to indicate the gas gravity.

PVT Samples

Important fluid properties are determined from analysis of oil and gas samples taken from the separator, including bubble point pressure, formation oil volume factor, and formation gas volume factor. These factors are important inputs for modeling to predict the recoverable reserves of oil and gas in the reservoir.

Taking PVT Samples

In order to take representative samples for PVT analysis from a separator, it is necessary to maintain the pressure in the sample container equal to the separator. Oil sample cylinders contain pistons; the chamber below the piston is oil filled and pressured with a hand pump to separator pressure. A fill line from the oil sight glass connects to the sample chamber above the piston, and an additional vent port facilitates removing air from the fill line. Slowly bleeding the oil from the lower chamber into a graduated cylinder allows the sample chamber to fill without dropping the pressure below the separator

vessel pressure. After acquiring a sample, typically 600 cc, closure of the oil drain and sample chamber valves isolates the sample inside the cylinder.

At the same time, a companion gas sample from the gas outlet of the separator completes the PVT set. A gas sample cylinder is larger than an oil cylinder because of the compressibility of gas; a larger volume is required for recombination. Instead of gas displacing oil behind a piston, gas expands into a vacuum-filled sample bottle to avoid air contamination. The procedure requires opening the sample inlet valve slowly to allow gas to fill the bottle over the same period that the oil sample takes to fill — typically at least 30 minutes to ensure a representative sample.

Records of each sample bottle number, together with the time taken, production data, and final sample pressures, allow comparisons and quality checks between samples.

A great deal of care is taken to ensure that sample bottles are cleaned in preparation to receive samples; the well test engineer inspects the certificates to show that every container has been prepared beforehand. Upon

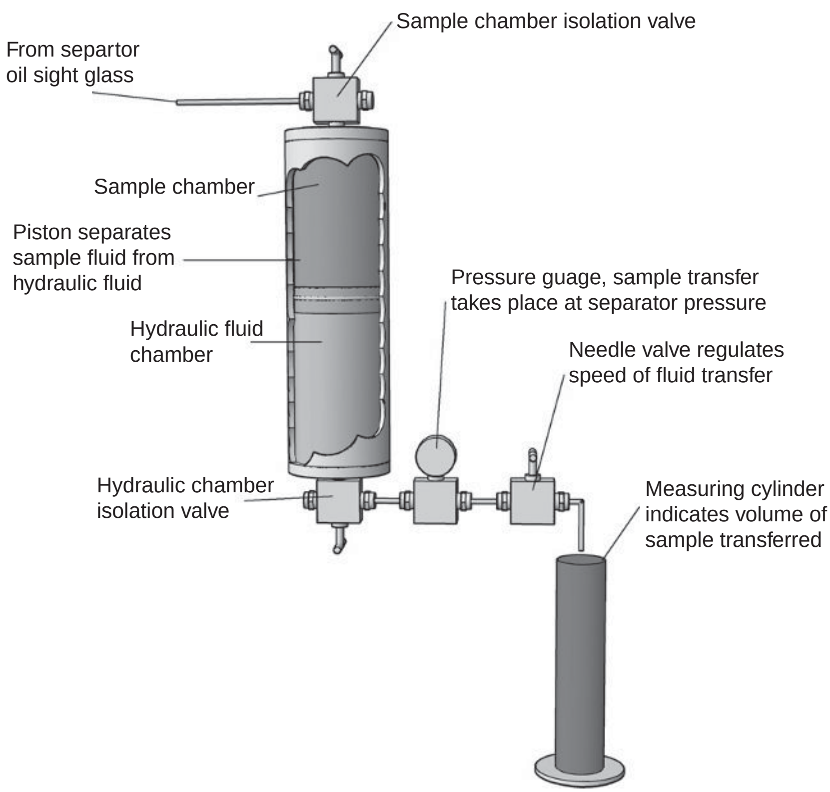


FIGURE 3.19 PVT oil sample set up

completion of sampling, every container is sealed, carefully labeled, and packed for shipment to the PVT laboratory for analysis.

Monophasic Samples

Occasionally, the oil produced at surface is above bubble point. In this event, it may be practical to take monophasic oil samples from a sample point on the high-pressure equipment, for example, at the choke manifold. This sample is valid only if there is no water production to contaminate the sample.

OIL AND GAS WELL TESTS

Identifying fluid properties and providing production data for flow assurance are common well test objectives. Yet the well test engineer must have some knowledge of the fluid properties beforehand in order to design a fit for purpose well test. The range of possible fluids provides a range in fluid behaviors, each of which reacts differently inside process equipment and presents unique challenges. For an exploration well test, the reservoir engineer provides information about the expected fluid properties based on data available. This data may come from a number of sources

- Offset wells drilled nearby through the same or similar formation structures.
- Geologic information from seismic and other survey data.
- Logs from electronic and nuclear measurements of the properties of the formation rock and fluids.
- Core samples taken during the drilling phase.

Whether the expected fluid is oil or gas, the range of properties possible to each serves to make every well test different. The remaining sections of this chapter discuss various fluid properties of particular interest to the well test engineer for planning purposes. Some of these properties present challenging production conditions that require significant planning. If during a well test, an unplanned environmental variable, such as high wax content manifests itself, it would be costly and impractical to redesign the test to accommodate the condition. Such an occurrence might well compromise the well test objectives.

Gas to Oil Ratio (GOR)

Crude oil or petroleum production occurs to varying degrees in association with some natural gas. In the reservoir, gas may exist entirely in solution with the oil, above the bubble point pressure. If the oil is saturated, a gas cap may be present above the oil. During production, fluid pressure drops, and at some point, it will fall below bubble point, in the near wellbore area, in the production tubing, or in the surface equipment. To the well test engineer the amount of free gas present is important for a number of reasons. In the first instance,

it is an important property of the oil and is information the reservoir engineer needs for modeling. Second, the GOR affects the behavior of the produced fluid during the well test. Gas bubbles forming downhole or in the production tubing lighten the fluid column, thereby lifting the liquid and generating a higher pressure at surface. The presence of gas along with oil requires that the surface process equipment be capable of handling two phases. Measurement of the production rate and the acquisition of samples for each phase are important in identifying fluid properties that will later help to determine commercial hydrocarbon reserves.

Dry Gas Well Tests

A reservoir may consist almost entirely of gas with little associated liquid oil. Little pressure loss occurs between the reservoir and the surface due to the low specific gravity or weight of a hydrocarbon gas. Typical values for a gas gradient are (0.1 to 0.2 ppf); consequently, high surface pressures are often a feature of gas well tests.

Gas is highly compressible. Inside vessels, pipework, and valves, gas carries a great deal of potential energy. The design of the process components is such as to allow the transfer of gas from one section of the process to the next in a controlled manner. A significant pressure drop can occur across the choke manifold, regulating pressure to protect low-pressure equipment downstream. As gas expands, a rapid drop in temperature naturally occurs, which can lead to process problems. In particular, hydrates are hydrocarbon ice crystals that form whenever certain conditions of pressure, temperature, hydrocarbon gas, and free water coincide. In addition to a pressure and temperature drop across the choke, gas undergoes a rapid increase in velocity. The presence of solids in the gas, such as fine sand particles, act as an abrasive against the walls of the pipework and process equipment. Erosion occurs rapidly where upsets in the process pipework result in turbulence and high velocity. This occurs at pipe elbows and changes in pipe diameter. Gas traveling at great speeds is associated with a considerable level of noise. Under the right conditions, the velocity of gas traveling through the pipework can reach sonic speeds.

Condensate production frequently occurs in association with gas. Generally produced in relatively small quantities, it is convenient to express the ratio of condensate liquid to gas production as a condensate gas ratio (CGR). Expressing the liquid to gas ratio in this manner is easier for planning purposes to anticipate the amount of liquid that the process equipment will have to handle. Measuring this liquid production in a test separator can be difficult owing to the small volumes produced. Condensate tends to accumulate in the production string until carried to surface in “slugs” and enters the separator at irregular intervals. It may take considerable time to accumulate sufficient volumes for metering or gauging.

Gas production frequently occurs with hydrogen sulphide (H_2S) and carbon dioxide (CO_2) present in the produced fluid. Both can cause corrosion

in the process equipment and potentially cause elastomer seal failure. (Refer to the sections on H_2S and CO_2 later in this chapter.)

Heavy Oil

Heavy oil associated with low wellhead pressure, low GOR, and high viscosity presents particular handling difficulties in the separator, the metering tank, and the burner head. At every point in the process, it presents increased resistance to flow compared with lighter fluids. Heating the oil and providing a high-specification transfer pump will help alleviate these handling issues. If left to cool inside tanks and vessels, its resistance to flow may increase further and may be difficult to dispose of. In severe cases, tanks fitted with steam coils are necessary to keep the oil warm, and in some instances, mixing diesel in the tank or spiking the produced oil with diesel will further aid handling. Burning heavy oil requires particular attention to reduce the risk of fallout and environmental contamination. High-specification burners are essential along with extra compressors to provide energy for atomization.

Wax

Hydrocarbon crystals form when crude oil drops below its cloud point temperature to form a solidified wax. Wax content will vary from one type of crude to the next. In some parts of the world, the onset of wax formation and the buildup of solid deposits on tubing and pipework are such as to restrict production rapidly soon after the temperature of the fluid falls below the cloud point temperature. This is also referred to as wax appearance temperature.

Cooling may occur through contact with a cool surface, such as at production start-up. It also occurs when production stops and the well fluid loses heat to the surrounding environment. This can happen in the surface facility, around the seabed and riser, and in the production tubing. For an exploration well test, the exact nature of the reservoir fluid is unknown; however, offset data may provide an indication as to the likelihood of a wax problem. In general, management of waxy crude entails heating of the crude at surface and may include the injection of chemicals, pour point depressants, at surface and downhole to help prevent wax formation. A heat exchanger positioned just after the choke manifold helps to control fluid temperatures. In areas where wax formation is expected and where it may become severe, additional measures might include heat tracing of pipework and instrumentation using steam or electrical coils. Steam heat tracing involves wrapping a copper tube around the pipework and instrumentation and circulating steam through the tube in order to heat the pipe. Electrical heat tracing works in the same way, except it uses an electrical heating cable instead of tube. Insulation wrapped around the tube or cable and pipe helps to reduce heat loss to the environment.

An additional problem occurs in the test string after production stops, the temperature in the production string drops, and wax forms along the length of the tubing. If this occurs, it may be difficult to move the fluid in the tubing

later, either for additional production or to reverse the tubing in preparation to kill the well. Planning should include procedures to displace the waxy oil with some other fluid immediately after a shut in. Because of this problem, the nature of a production test with waxy crude may follow a different sequence to other oil tests. The planning team will minimize the number of shut-in periods to avoid repeating this procedure too often.

Foam

In a well test facility, the presence of foam can result in a number of operational problems. Foam bubbles occupy a volume many times larger than that occupied by liquid alone and result in premature filling and carryover in tanks and vessels leading to possible environmental contamination. Foam also causes problems in metering devices and instrumentation such as sight glasses and level controllers on separators and tanks designed to work with single-phase fluids, liquid or gas. Foam severely impairs the ability of instrumentation to monitor and control the fluid, resulting in unpredictable outputs from instrumentation and control devices.

Foam tends to occur with heavier high-viscosity oil associated with high GOR values. Foam bubbles form from the heavier gases, C2-C3 and CO_2.

Management of foam for a well test requires some additional features — for example, larger capacity separators to permit greater retention times, knockout vessels to capture liquid carryover, and, where space permits, the inclusion of additional settling tanks. Gas injection into the separator vessel may also assist the small foam bubbles coalescing with the injected gas to more readily separate from the liquid phase. Injection of chemical foam breakers can also help. However, such chemicals are usually custom designed to suit specific crude oils;given the unknowns in an exploration well test, off the shelf chemicals are not always effective.

The multiphase flowmeter provides a novel new technology solution to the problem of metering foaming oil. These devices are increasingly common in well tests and do not require phase separation of oil and gas for metering. The multiphase meter works by measuring mass flow for each phase simultaneously based on radioactive absorption from a source positioned close to a venturi. This device does not necessarily eliminate the separator from the setup, since phase separation may be required to dispose of the fluids at the burner head. Combined oil and gas production through a single flow line to the burner head may create excessive backpressure and limit the maximum achievable flow rate. However, operation of the separator is simpler because it is no longer required for metering purposes.

Heat Radiation

This discussion centers on the heat (or thermal) radiation associated with the disposal of oil and gas during a well test. (Refer also to Chapter 6 for further discussion on this topic.)

The heat radiation generated when burning crude oil becomes a significant design consideration above values of about 5,000 bopd. This figure varies considerably according to the efficiency of the burner, the length of the flare boom, and the cooling systems available. Even at moderate temperatures, personnel can experience some pain on exposed areas of skin; the sensation of pain and the damage caused increases rapidly with each additional degree rise in temperature. API Standard 521 includes some references in relation to thermal radiation and personnel exposure.

Heat radiation affects both personnel and equipment. Planners have to consider the effect on personnel working in exposed areas or moving along exposed access routes. They also have to examine the effect of high temperatures on the range of materials exposed to heat radiation during flaring. Examples include communication domes, electronic sensors, paint surfaces, pressurized gas and oil cylinders, tanks, tarpaulins, lifeboats, crane jibs, jacking legs, motors, containers, and hard hats. All may suffer consequences, ranging from peeling paint and deformation of plastic to fire and explosion.

In addition to the effect of direct heat radiation, heat will also be transmitted by conduction though metal surfaces. On offshore facilities in particular, planning must include the monitoring of surfaces that will experience heating in this manner. Examples include column legs, tanks, containers, accommodation structures, crane pedestals, and crane housings. Materials stacked against bulkheads and container walls might experience dangerous temperatures rises if not properly monitored.

With adequate planning, sufficient resources can be mobilized to manage the risks associated with heat radiation. Planning should include meetings with the well test contractors involved with flaring, including the surface equipment contractor and specialist heat suppression contractor, if used, to discuss the issues. The surface contractor should supply a heat radiation report that provides a calculation showing the heat intensity at various distances from the flare based on certain modeling inputs. These inputs include the maximum flow rates expected, fluid type, flare boom length, and water curtain details, including assumptions regarding the efficiency of the water curtain and conservative wind conditions. The output from the report is heat intensity given in units of kilowatts per meter squared (kw/m^2) or in British Thermal Units (BTUs) at various points away from the flare. Of particular interest is the heat intensity along the handrail of the facility since this is the point of greatest heat intensity that could affect personnel and the facility.

The controls available to manage heat radiation risks include utilization of flare booms of adequate length to remove the heat source to as great a distance as possible from the side of the facility. Typically, 25 m is the longest length available. Ensure an adequate water cooling system is available just behind the flare and or at the handrail, or positioned strategically to protect other parts of the facility, for example, cranes, anchor winch structure, and helidecks. Many older facilities have limited water cooling available for this

FIGURE 3.20 Photograph well test flare with cooling and heat shields. Photo by kind permission of Santos Limited, (Australia)

purpose, and it may be necessary to utilize a dedicated water-cooling service contractor to provide additional resources. For example, monitors should be positioned at points along the handrail where heat intensity will be at its greatest, based on the heat radiation report. Heat shields in the form of fire-resistant blankets provide shielding to personnel and equipment, in particular electronic devices and flammable fuel sources, and reduce reliance on water cooling. The effects of heat radiation should be monitored continuously throughout the flaring operation, and dedicated personnel should be assigned to adjust the cooling and heat shields to the conditions.

Ultimately, the well test crew has the additional control available for shutting the well in or reducing the flow rate by introducing a smaller choke restriction.

Noise

A drilling rig, whether land based or offshore, is typically a noisy environment. Background noise derives from the myriad pieces of machinery and the activity of equipment constantly moved to feed the needs of the facility. Examples include tractors, cranes, tuggers, generators, compressors, pumps and fans, rolling pipework, and personnel using hand tools. Offshore, the activity of all of this equipment operating within the confines of a relatively small metal structure compounds the problem of noise.

Numerous international regulations and standards define noise intensities acceptable for a normal working environment; in general, most consider exposure to levels up to 85 dB for an 8-hour work period as the upper limit. Partial

or permanent hearing damage can occur above this level. Planning controls for this hazard include access restrictions, hearing protection, and alternative communication means. Correct use of hearing protection is essential; incorrectly fitted or partial use of hearing protection increases the risk of hearing damage. Earplugs handled with dirty hands can also spread ear infections. A reduced ability to communicate presents a more immediate safety hazard, since many operations at a well site are hazardous and or complex and rely on communications for their safe execution. Examples of such communications may include something simple such as warning personnel about an overhead lift with a crane, or a more detailed instruction regarding the manipulation of well test equipment. Gas traveling through well test production equipment can reach sonic velocities and generate noise intensities well above those considered safe for unprotected hearing even for short periods. At these levels, personnel need to shout to be understood even standing next to one another. During well test activity, all nonessential operations should cease, for example, crane activity. This eliminates the hazard associated with dropped objects over the test equipment and eliminates the need for well test personnel to stay alert to overhead lifts in an environment where they cannot hear the crane. Other aids to communication include

- Detailed and clearly written set of procedures
- Toolbox talk prior to operations
- Handover between shifts
- Headset communication devices

Using these tools, personnel involved with the operation have an increased level of awareness of the operation and their role, and become less dependent on verbal communication.

Hydrogen Sulphide

Hydrogen sulphide (H_2S) is a highly toxic sulphur compound sometimes produced with natural gas, also referred to as sour gas. By contrast, gas-produced H_2S free is sweet gas. When planning an exploration well test, the reservoir engineer may not have a good handle on the likelihood of H_2S production. Offset data can be a good indicator, but often, the best the reservoir engineer can do is to indicate that it is not expected. In light of this uncertainty, it is good practice to have at least some contingency plans in place to monitor for the presence of H_2S and to provide an appropriate response plan should it occur.

For the well test engineer, planning for H_2S must consider both the safety of personnel and the suitability of equipment. The differing policies and practices of the various contractor companies all add to planning complexity. Typically, the well test engineer will review the policies of the oil company, the rig contractor, and the principal well test contractor. Some company

procedures stipulate that a breathing apparatus be used by all personnel if the concentration of H_2S in the flow stream exceeds 50 ppm; for others this value may be higher or lower. Aligning the different policies and developing a well specific H_2S plan are part of the process of preparing the well specific procedures. (Refer to Chapter 6 for a continuation of this discussion.)

H_2S is measured in units of (ppm) parts per million; 10,000 ppm is equivalent to 1 percent by volume. In atmosphere only a few hundred ppm can be fatal to personnel. Most standards specify an allowable concentration of 10 ppm for working in this environment without special measures. However, most companies would consider the continuous presence of H_2S in the atmosphere as unacceptable. Plans therefore usually consider the concentration of H_2S in flow stream as opposed to atmosphere and the consequence of a release from the flow stream either as a result of a deliberate release to the atmosphere, for example, when sampling, or as a result of an accidental release, for example, following a seal failure. An H_2S plan should also consider flaring activity during a well test. H_2S produces sulphur dioxide, as a product of combustion, which is a toxin. In the event the flare extinguishes, there is a potential for a significant release to atmosphere. Special consideration as to wind direction and strength should be included in the plan. The plan should also stipulate a minimum wind strength and direction in order for flaring to continue.

Apart from its highly toxic properties, H_2S can contribute to metal corrosion and, in particular, to a process known as sulphide stress cracking, in which H_2S reacts with water and CO_2 to cause metal embrittlement. In order to handle fluids in which H_2S is present, special materials, which are resistant to sulphide stress cracking, are required. This is particularly important at higher pressures and temperatures where the process of sulphide stress cracking accelerates. Flow-wetted surfaces, that is, surfaces exposed to production well fluids, should have an H_2S service specification. For metallic surfaces such as tubulars and tool components, materials with a lower hardness are more resistant to the sulphide stress cracking.

For H_2S expected wells, specialist service companies specifically qualified to provide training and equipment for working in toxic hazardous environments should be engaged to assist in managing the hazard.

References for H_2S planning include API RP 49 Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulphide and NACE MR 01 75 for materials.

Hydrates

Hydrates are icelike solids formed by the interaction of hydrocarbon gas and water under the right conditions of pressure and temperature. These conditions vary according to the type of gas; generally, a heavier gas will form hydrates at higher pressures.

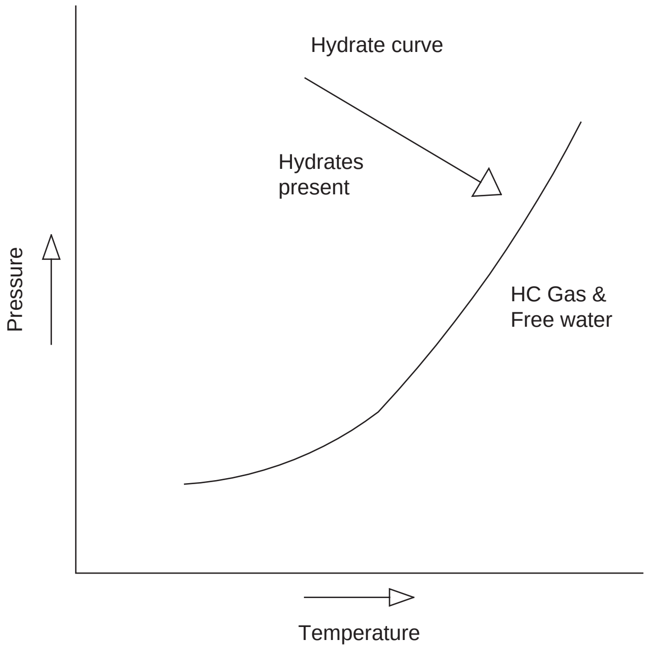


FIGURE 3.21 Hydrate curve

For a given gas gravity, it is possible to plot a hydrate curve on a pressure versus temperature graph. Within the range of the curve, hydrate formation is likely, provided free water is present.

In practice, this means hydrates can form almost anywhere in a well test system and are capable of occurring at temperatures above the freezing point of water. Hydrate solids cause serious operational problems during a well test and are capable of plugging instrumentation, pipework, valves, meters, chokes, and so on. They can also form solid projectiles, which can travel rapidly along production pipework, causing damage to equipment downstream. Once hydrates start to form, the problem continues to worsen unless immediate remedial action is taken. In severe cases, this will result in a well shut-in and in bleeding the system down slowly so that the hydrate plug or plugs can dissolve naturally. Even with preplanning, a well test system in which hydrates have started to form can behave unpredictably, with pressure and temperature drops occurring where they were not expected. The cooling of the gas may take place in one spot; however, the contact with water may occur elsewhere, resulting in the formation of a hydrate plug where none was expected.

Planning and designing a well test that has a potential for hydrates has distinct facets: prediction, prevention, identification, and remediation. Almost every gas well test has a potential to form hydrates; using offset data, hydrate curves and geology provide the means to predict its likelihood. A significant

hydrate risk may prompt the well test engineer to consider significant changes to the well test design.

The three controls available for hydrate prevention are chemicals, fluid heating, and control of system pressures. Chemicals that increase the hydrate formation temperature or that inhibit or dissolve hydrates form a first line of defense; typical of these chemicals are methanol and glycol. Methanol is an alcohol that is clear in appearance and has a similar viscosity to water. Its low viscosity makes it ideal for injecting into the flow stream, particularly subsea, at the mudline, and in some instances below the mudline. Methanol helps to prevent the formation of hydrates chemically and to dissolve hydrates after formation. Where severe hydrate problems are anticipated, significant volumes of methanol must be available, with pumps of adequate specification to deliver the volumes required. If the well is expected to operate with high surface pressures, then the pump selected should be capable of delivering the required methanol volumes at the maximum expected well test pressures. The elastomer seals in contact with methanol must be suited to methanol service, usually a Nitrile or Viton polymer. Glycol, though effective in increasing the hydrate formation temperature, is more viscous than methanol and therefore is less suited to injection down long chemical umbilical lines. Glycol, however, is a safer nonflammable fluid and is well suited where large volumes are required, such as pressure testing of surface lines and pressure control equipment. A glycol-water 50/50 strength mix will effectively prevent hydrates from forming because of produced gas contacting pressure test fluids.

Heating of well fluids forms the next line of defense. Heat exchangers are standard components of almost all surface well test equipment packages. A well test heat exchanger comprises a series of pipe coils through which the well fluids pass. External to the coils, saturated steam supplied from a remote boiler circulates to heat the coils and their contents. Although the heat transfer efficiency for gas is not very high, at small choke sizes where the gas velocity is still relatively low, heating can be sufficient to prevent hydrates from forming downstream during the early part of the cleanup. The effectiveness of the heater may decrease as the well flow rates increase. However, the fluid temperature from the reservoir may also increase to offset this effect. Heating may also be applied elsewhere in the system; for example, the riser fluids may be circulated through a mud pit that has been fitted with steam coils and heated by a boiler. Note that such a measure would only be effective where a relatively small riser volume was involved. Electric or steam heat trace systems are also available which can be wrapped around pipework, valves, and instrumentation and then lagged with insulation. The need for such measures is a function of the expected likelihood and severity of the hydrate problem.

Other engineered prevention measures could include the layout of the equipment and pipework to minimize the number of internal bore upsets where gas cooling could occur, the elimination of dead spots in pipework

where water might accumulate, and the selection of tubulars to provide a uniform bore between the reservoir and the surface.

Positioning the choke manifold in an elevated position such that any liquid condensing at the choke outlet falls immediately away from the choke where gas cooling is at its greatest can help alleviate problems in this particularly vulnerable area. Ample chemical injection points should be provided around the system to direct methanol to trouble spots as needed.

Even with preventative measures, an exploration well test is full of unknowns, and the hydrate problem may turn out to be more severe than originally expected. The well test crew must be alert to unusual behavior in the system. Some external indicators can give clues as to the cooling taking place inside the equipment; an example of such an indicator is the appearance of snow on the outside of the pipework, This does not necessarily mean hydrates are forming, but the well test crew needs to be wary and closely monitor pressure and temperature drops in the system. Unusual pressure drops are the first real indicator that a hydrate problem exists; rapid action is required to prevent the problem from escalating. Additional heating should be provided from the boiler if available, methanol injected upstream of the problem area, and an injection point relocated if it is in an area where hydrates were not expected. The production downstream should be choked to reduce the pressure drop in the problem area. Most heat exchangers are fitted with choking devices alternatively adjust the separator pressure if the problem lies downstream of the heater. If none of these measures addresses the problem, changing the choke size to a larger one may reduce the cooling effect and raise the general system temperature.

If a hydrate plug forms, there is a danger that trapped pressure on one side will act to propel the plug as a missile once it starts to melt. The safest course of action is to shut the well in upstream and bled pressure carefully on both sides of the plug and allow the hydrate plug to melt. Injecting methanol may help to dissolve the plug if a suitable injection point is available.

Carbon Dioxide

Carbon dioxide is an undesirable by-product often produced with reservoir fluid. Measured as a percentage volume of the produced gas, it can be any value depending on the well.

The expected presence of carbon dioxide has two major planning consequences. Carbon dioxide can cause rapid deterioration of any elastomer materials with which it comes in contact, and, because it does not burn, it can affect the stability of the gas flare.

There is no direct rule for determining how much carbon dioxide will cause a problem. The risks associated in operating a system with carbon dioxide are dependent on the concentration of carbon dioxide, the pressure and temperature of the system, and the duration of the test. Typically, for concentrations above 5 to 10 percent additional planning should be in place.

Seal failure in the pipework or on any well test equipment may expose personnel to significant hazards from flammable hydrocarbons and the potential release of toxic gases such as hydrogen sulphide. Most well test equipment is installed using temporary pipework fitted with elastomer seals in almost every connection. In addition, there are elastomer seals in other well test equipment, downhole tools, packers, separators, chokes, pumps, and so on. Carbon dioxide reacts chemically with some compounds used in seal manufacture, and it also diffuses into the elastomer material under pressure. Explosive decompression of the seal can take place after the seal undergoes decompression. The risk of this happening increases according to the CO_2 concentration, the operating pressure, and the magnitude and suddenness of the pressure drop, for example, as the result of a choke change. Suitable seal selection and operating procedures that avoid rapid pressure drops will reduce this risk.

Basic precautions include selecting elastomers that contain compounds resistant to the effect of carbon dioxide and installing new seals, particularly for those connections exposed to high pressure on the gas lines. Other simple measures might include changes to the layout of test equipment to minimize the travel distance and therefore the number of seals in the gas circuit in preference to the oil circuit.

Some seal manufacturers offer seals capable of operating in high H_2S, CO_2, and high-temperature environments. However, for extreme conditions, the well test engineer might consider changing the temporary pipework fitted with elastomer seals to semipermanent pipework fitted with metal flanges and gaskets. This would be a costly option, for it would entail additional material, fabrication, and time to install. If the risks of CO_2 damage were high, this would justify the additional cost and engineering. Carbon dioxide does not burn; when present in significant quantities, this inert gas can affect the stability of a gas flare. The mixture just after the exit may be too rich to burn until it has dispersed and mixed with the atmosphere. Igniting the flare requires a pilot system that extends beyond the flare tip, or it may require the use of an oil burner head to generate a flame that extends beyond the gas flare tip to a point where the air-gas mixture is lean enough to burn. When significant quantities of carbon dioxide are present, the mixture is sometimes too lean to ignite normally. This problem can be alleviated in one of two ways: (1) reduce the choke size and therefore the gas velocity, or (2) where very significant carbon dioxide percentages are present, provide a gas flare line with a larger diameter to drop the velocity of the gas at the exit. This latter option requires significant time to engineer; changing the size of the gas flare changes the weight of the flare boom and might affect the overall rigging and support structure.

COMMON WELL TEST ENGINEERING CHALLENGES

Many of the special conditions discussed in this chapter share the characteristic that extremes require additional resources in planning, cost, and engineering to manage. The equipment and expertise required to operate at extremes, whether it is high pressure, high temperature, or any other variable, is usually more difficult to source. Failure to identify the need for a high-specification well test, or inadequate planning time allotted to prepare for such a test will more than likely result in a poor outcome in terms of well test objectives.

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Chapter | four

Planning Processes and Documents

CHAPTER CONTENTS

DOCUMENTATION

Well test documents detail planning processes and the output of those processes, that is, planning decisions. Documents also describe controls, both procedural and engineering, that are necessary to execute planning decisions. This chapter describes these planning processes and their associated documents (see Table 4.1 for an overview). Some of the documents that deal more with engineering controls are introduced here and described in more detail in Chapter 5, which focuses on engineering controls.

DOCUMENT CONTROL

Due to the important nature of the information contained in documentation and to the complexity and the number of parties involved in a well test operation, it is essential to implement document controls from the start of planning.

The purpose of a document control process is to ensure that information distributed to an extended group of individuals is current and accurate. In a well test organization, that group includes individuals and departments within a resource company organization, together with contractors and regulators.

Table 4.1 Planning Processes and Document Controls

Communications management	Document Control
Define objectives and test outline	Basis for Design
Secure contractor services	Contracts
Rig interface planning	Rig Visit Report
Logistics planning	Logistics Plan
Define management controls	Roles and Responsibilities
Detailed planning	Well Test Program
Program review	Test the Well on Paper
Engineering review	Well Test Validation
Safety planning	Well Test Safety Case

A great deal of information is disseminated to these groups in the course of planning. Without this control there is no mechanism to ensure that information reaches everyone; nor is there a mechanism to ensure the accuracy of that information. A document control process includes the elements of review, approval, and controlled distribution. The well test engineer authors some of the planning documents such as the Basis for Design and the Well Test Program; other documents are authored by the subsurface and drilling departments and still others by well test contractors. Each document requires review and approval prior to distribution.

A document controller is an individual assigned to manage the document control process. A controlled document requires a unique document number, issued by the document controller, together with a revision number to distinguish it from later revisions, a sign-off section to identify the personnel responsible for review and approval, and a distribution list of personnel and organizations to receive a copy. A document receipt is also included in the control process to record that all parties identified on the distribution list have received copies.

Some documents are not controlled by the procedure described but are nonetheless important documents. Documents in this category are called living documents because they change continuously as operations progress. An example of such a document is the Job Safety Analysis or JSA, the JSA is a tool used by the workforce to review and risk assess each task prior to commencing work. Documents such as the JSA evolve continuously through additional input provided by the workforce and through learning from experience.

INITIAL PLANNING AND BASIS FOR DESIGN

A well test is a well objective identified by the subsurface team; data gathered from a well test provides input to help build a reservoir model. This objective is identified in a Basis for Design document submitted to the drilling

department along with other objectives and data required to develop a well design. The well test plan is little more than a line item or short section detailing some well test objectives. At this point the well test engineer becomes involved, developing the plan to a degree sufficient to identify the services required and any particular design issues that might require special attention. This planning requires meetings within the drilling department and with the subsurface team. The well test objectives, i.e. the data objectives required by the subsurface team to help develop the reservoir model, are central to well test planning. The role of the well test engineer is to identify how to go about achieving those objectives in a safe and cost-effective manner and to highlight to the subsurface team the challenges associated with each objective so that the subsurface team can make a value of data assessment, sometimes modifying the objectives accordingly. In the course of discussing the well test objectives, the well test engineer identifies the services required to achieve them. Most of the services required are common to many well tests, TCP, downhole test tools, gauges, tubing, tubing handling, surface well test, and sampling. Some special services might also be identified, such as nitrogen to provide a high underbalance pressure, sand control or sand detection, and wireline services to correlate or perform other specialized through tubing operations.

The information gathered from this initial planning is collated by the well test engineer into a new or revised Basis for Design document. This document must communicate the information necessary for contractors to develop detailed planning. The Basis for Design is a controlled document reviewed by those who have had input into it, in particular the subsurface team.

Elements of a typical Basis for Design document include

- Reservoir Data
- Well Information
- Well Test Objectives
- Facility Information
- Well Test Services
- Flow Schedule
- Program Outline

A basis for design document need not be a particularly large document. Much of the data may be presented in table format, and the description of the services and the program outline can generally be contained within a few pages.

Reservoir data, frequently presented in table format, lists reservoir fluids and conditions, especially fluid characteristics that require special planning attention, foam, wax, H_2S or CO_2.

Well information provides depth and geological data, which provides input for the well design. This information is used by the drilling department to develop the casing design and the drilling program and by the well test engineer and contractors to determine the test string design and the well hydraulics.

The *well test objectives* provide input to many aspects of the well test design, including the flow and shut-in schedule, the maximum overall flow rates, sampling requirements, and the type, quantity, and location of gauges.

Facility information communicates basic information regarding the name and type of facility and details of the facility owner's office contact details. More detailed information regarding the facility follows the rig visit. If this has been completed, then the rig visit report might be issued in an appendix or as a separate document along with the Basis for Design.

Well test services are listed along with information regarding the proposed plan for each. This information gives contractors an indication of the scope of supply for their service. For example, if TCP services are required, the Basis for Design will indicate the size and type of gun system proposed. Details will include the proposed firing head system and any contingency systems the resource company considers appropriate.

The *flow schedule* lists the intended flow and shut-in durations, as well as the proposed flow rates. Contractors use this information to plan equipment specifications it also provides input to the Well Test Program and the Safety Case.

The *program outline* lists the proposed critical path procedural steps in sequence, together with an estimate of the time required for each. This information is useful to all parties as it indicates the resource commitment required to conduct the well test.

Once approved, subsequent planning for the well test will take place following the information outlined in the Basis for Design. Changes to the information supplied in the Basis for Design require document revision and redistribution. Small, apparently insignificant, details can materially change well test design features. For example, if revisions to the reservoir model predict water cut during the test, this can significantly impact the design of the surface facility hardware, possibly necessitating a new service contractor to provide water processing equipment and expertise.

The Basis for Design is issued to every party that may contribute to well test planning, including the subsurface team, the drilling department, and all of the well test service contractors.

A sample Basis for Design document is provided in the appendices.

THE CONTRACTS PROCESS

At a basic level, a contract is an agreement between a resource company and a service contractor to supply well test services at an agreed price.

The contract process starts with a request for bid document, in which a resource company invites service contractors to bid competitively for well test services. It continues with the evaluation of the contractor bids and finishes with the award of contract.

A less formal process a request for quotation is occasionally utilized in circumstances where the schedule requires a contract in place quickly. This basically entails a contractor issuing a quotation to perform work on a one off basis.

If every well test service were required, there could potentially be a requirement to set up a separate contract for every contractor. In practice, some contractor companies provide more than one of the well test services. Utilizing one company to provide multiple services reduces the number of contracts. However, the technical input required to define the scope for each service remains the same. In order to reduce the administrative exercise associated with the contracts process, and to secure long-term commitment, many resource companies hold extended contracts with well test service contractors. Consequently, the well test engineer might join a planning team in which many of the contracts are already in place.

Request for Bids

Preparing a request for bid takes place over a period, sometimes weeks, during which, the well test engineer often has discussions with local service contractors to help reach a decision on the appropriate content in the request for bid document. From these early discussions, the well test engineer determines what contractors are available, what services they can provide, and whether or not they are in a position to bid for the work. The discussions help the well test engineer to better understand the needs of the resource company; service contractors can provide valuable technical advice that provides input to the request for bid document.

The structure and content of individual contracts vary from one company to the next. Large organizations have contracts departments dedicated solely to the task of managing contracts. Within these organizations, the input from the well test engineer may be limited. However, the well test engineer must evaluate the technical content at the very least to ensure that the scope of supply covers the nature of the work to be carried out.

Below is a generic description of a well test service contract, followed by a description of the process involved with each element listed in that structure.

- Covering Letter
- Response Checklist
- Contractor Qualification
- Scope of Work
- Scope of Supply
- Pricing Structure
- Alternative Pricing Proposals
- Terms and Conditions

Covering Letter

A covering letter is included with every request for bid to provide information and instructions as to the bid process. A typical covering letter might include information relating to each of the following headings.

- Contracts Focal Point
- Acknowledgment
- Bid Closing Date
- Clarifications
- Assessment Loadings
- Executive Summary

CONTRACTS FOCAL POINT

A contracts focal point is the position to which all correspondence between the resource company and the contractors shall take place. This position shall also be the addressee for contractors to send correspondence and completed bid documents.

ACKNOWLEDGMENT

Contractors intending to bid for work should provide a written acknowledgment for receipt of the request for bid document and a notice of their intention to bid for the contract. This is in order that the resource company can be assured that each service shall receive a bid; if not, the resource company may have to cast further afield to obtain contracts for all of the services required.

BID CLOSING DATE

Specifying a closing date deadline promotes competitiveness. The resource company should select the closing date with care, giving contractors adequate time to cost and source everything defined in the scope of supply. A rushed response is likely to lead to problems later in the contract. Contractors require time to source equipment, in particular specialized equipment, for example, a deepwater subsea control system or high-rate separator. Delivery schedules have to be confirmed with suppliers, and in some instances pooled equipment availability needs to be confirmed between the local contractor representative and their regional headquarters. With insufficient time to thoroughly investigate schedules, technical research, and pricing, contracts are liable to be vague or attached to numerous conditional clauses and to include inaccurate delivery schedules that could lead to significant additional cost later on.

CLARIFICATIONS

Regardless of the resource company's thoroughness of preparations, contractors frequently require clarifications on aspects of the request for bid

document. Clarifications can relate to any aspect of the request for bid, technical, pricing, legal, or queries regarding the bid process itself. The response to a request for clarification constitutes a change in the request for bid document. Providing a reply to an individual contractor is to give that contractor a competitive edge. For that reason, certain rules apply in respect of clarifications, namely,

- Clarification responses are made available to all contractors intending to bid and include the wording of the original clarification request.
- Clarifications are distributed anonymously; that is, they do not identify the contractor requesting the clarification.
- A clarifications closing date applies beyond which contractors can no longer request further information regarding the contract. This is in order that changes to the request for bid do not occur late in the process when it may be too late for some contractors to respond to those changes.

ASSESSMENT LOADINGS

Resource companies might emphasize certain features of a contract that are deemed important — for example, features relating to improved safety or reliability, lower cost or staffing levels, new or proven technology, and local content (e.g., a locally sourced and based skill force or a support facility close to the area of operations).

EXECUTIVE SUMMARY

Contractors are invited to provide a covering letter in their bids with an executive summary. This short descriptive overview is an opportunity for the contractor to highlight particular features of the bid to which they wish to draw attention. This assists the resource company in the evaluation process, particularly when applying assessment loadings.

Response Checklist

A response checklist is a quality control tool for the benefit of both the contractors and the resource company. The checklist itemizes each criterion that contractors must satisfy in order for their bid to be eligible for evaluation by the resource company. By following the checklist, contractors ensure that their bids are complete and therefore eligible. For the resource company it is desirable that all contractors' bids are eligible since it increases the likelihood that it will have competitive bids to evaluate.

Contractor Qualification

Because oil and gas operations are hazardous and involve risk to personnel, resource companies develop safety management systems in order to help reduce that risk. An important element in any safety management system is

contractor management. Contractors represent a significant risk because they source and train their own personnel, develop their own procedures, and fabricate, source, and maintain their own equipment, all of which are largely outside the control of the resource company.

In order for contractors to be eligible for evaluation, it is essential that they are subjected to a qualification process in which the resource company audits the contractor's management systems to ensure that they follow processes that are in line with, and acceptable to the resource company. In other words, by engaging the services of a particular contractor, the resource company avoids the introduction of an unacceptable level of risk. Many resource companies prequalify certain contractors, prior to, or as part of, the contracts process, utilizing internal or third-party audits. Audits can evaluate both HSE and technical processes within contractor organizations.

OTHER INSTRUCTIONS

In addition to specifying what HSE and technical criteria are required in the bid documents, the resource company may also stipulate the level of detail required for each. In doing so, the resource company clearly defines its expectations for the service required. In turn, this aids the contractor in submitting competitive bids since it ensures that all bids carry a similar level of detail. In most instances, the level of detail required is dependent on the size and scope of the contract. A long-term contract covering a high profile or comprehensive workscope is likely to attract greater scrutiny.

EXAMPLES OF HSE QUALIFICATION CRITERIA

Contractors should demonstrate that they operate with an effective safety management system. Details of the safety management system should be included with the bid.

The contractor shall supply 12 months of HSE statistics in the format specified in their safety management system. The resource company may require contractors to report HSE statistics in a predefined format in order that contractor HSE performance can be compared.

The contractor should highlight safety initiatives in relation to the proposed scope of work.

Examples of Technical Criteria

For the equipment listed under the scope of supply, the contractor should specify the manufacturing standards applicable for the main items.

The contractor should detail the processes in place to maintain equipment in accordance with their manufactured standards. Include the frequency and type of service work required for each of the main components. Where practical, include sample maintenance records.

For the equipment listed in the scope of supply, contractors must specify the safe operational working limits.

Indicate the standard for operating practices offshore. Where practical, contractors should supply an operating manual or a representative sample from an operating manual.

Supply track records of operations performed in the last 12 months; include details of the operating environment.

Scope of Work

A scope of work is a description of the service required by the resource company together with a description of the environment in which that service will operate. This aspect of the contract requires input from the well test engineer since it requires technical knowledge of well test services. An incomplete or inaccurate scope of work exposes the resource company to the risk of entering into a contract ill suited to its needs. This is particularly important where the well test requires specialized equipment to operate in extreme environments. Take the example of an operation that requires work in deepwater operating from a dynamically positioned vessel. The subsea equipment required to work in these conditions is difficult and expensive to source and secure. If not identified in the contract scope of work, the resource company runs the risk that this equipment will not be available for the operation. At the very least, the contractor is likely to charge a significantly higher rate to source and supply specialized equipment not listed in the contract.

Scope of Supply

The scope of supply identifies the equipment required under the contract to perform the scope of work. Where there is some uncertainty as to the equipment required, the resource company might invite contractors to submit technical proposals. Similarly, there might be uncertainty as to how to conduct a particular operation. Again the resource company might invite contractors to submit proposals as to how to achieve a particular objective. The well test engineer preparing the contract may invite such proposals anyway since it allows contractors the opportunity to provide innovative solutions and new technology. The equipment deemed necessary for the operation can be presented in a simple table listing each item along with the specifications required for each.

Pricing

In order to facilitate comparisons between competing bids, resource companies provide pricing templates for spreadsheet input together with planned operation timing, against which the resource company invites bidders to submit an example job invoice. Resource companies might also require individual

pricing for each item in the scope of supply. However, contractors often choose to submit alternative pricing proposals as addenda to their bids.

Most contractors charge a mobilization fee that includes the costs associated with preparation of the equipment. These preparations include the preparation of lifting certification, packaging into transport containers, compiling packing lists, and equipment certification.

A standby rental charge applies to individual items of equipment or to equipment packages, a package being a set of equipment particular to one service. For example, a data acquisition package might include computers, sensors, and cabling.

These charges usually apply for a minimum period, typically 30 days. In remote locations, the minimum period is longer by several months, depending on the time required to mobilize and demobilize the equipment.

Operating charges apply based on equipment usage. Agreement as to how and when operating charges apply is often a point of discussion. Some service contractors apply these charges from the moment they arrive at the well site or offshore facility, others when personnel arrive, and still others apply charges only after the equipment has been tested and fully commissioned. In most, but not all, contracts, standby charges stop when operating charges apply.

Personnel charges apply on a fixed per day rate when personnel are mobilized from an agreed point of origin. Depending on the contract, some hotel and transport charges are also added to the personnel rate.

Personnel support charges relate to specialists supplying expertise to the resource company during the planning phase. Personnel are assigned exclusively to the resource company for an agreed period to liaise with the resource company to provide technical support.

Contractors also charge for consumable items, damages, and handling fees for third-party equipment and services.

Terms and Conditions

Every organization has legal caveats which they add to their contracts. These terms and conditions are intended to protect the company from liability in the event an incident resulting in potentially damaging legal costs and to ensure that they are not exposed to excessive penalties or other hidden charges in their contract.

Terms and conditions are attached to the contract by the legal department. The well test engineer rarely becomes involved with this aspect of contracts.

Evaluating Bids

Once all of the bids have arrived, or the submission period has elapsed, the well test engineer may be required to evaluate bids and recommend a contract award. Alternatively, the well test engineer might only evaluate technical aspects of the bids, while management and the legal department evaluate other aspects.

The qualification has been completed prior to this stage; if not, then the evaluation might also assess contractor safety management systems. This part of the evaluation is more often a duty of the company safety inspector or third-party auditor acting for the resource company.

The evaluation process takes the following steps:

- Assess each bid to ensure that all of the requirements from the bid checklist have been met.
- Disqualify any bid that has failed to meet any of the criteria which the resource company identified as mandatory.
- Compare all bids on the basis of the assessment criteria, HSE, Technical and Pricing.
- Apply the merit loadings as appropriate.
- Issue a recommendation based on the outcome.

It is essential that the well test engineer follows the process set out in the request for bid document. Contractors expend a great deal of effort and resources to prepare their bid documents; they do so in a manner that reflects how the company stated it would evaluate the bid. To change the evaluation process would ignore the efforts contractors made to customize their bid and could discourage that contractor from bidding for work with the same company in future. It would also defeat the intent of the bid process to achieve competitiveness, since the evaluation would not assess the information supplied, but would instead utilize some other criteria which most of the contractors were not given the opportunity to address.

TECHNICAL EVALUATION

Technical merit can manifest itself in a number of product features, features that save critical path time, acquire or measure well test parameters, and provide superior quality data, reduce risk to personnel, address particular design features of the test, smaller footprint on deck, faster installation time, higher specification, or simple to operate.

Contractors offering new technology often make claims regarding that technology which are difficult to measure or verify because of the lack of field data. In order to assess the merit of a technical proposal, particularly one involving the use of new technology, the well test engineer must look at all the evidence in support of the proposed technology, technical data, usage history, factory or lab test data, field trials, and failure reports. Accepting new technology at face value is a risk. Without a field-proven history, the resource company has no other assurance that the technology will perform other than the evidence provided by the contractor offering the technology. If, however, the benefits are self-evident, then the merit loading, if any, will apply

PRICING EVALUATION

The simplest method to compare the pricing offered in each bid document is to prepare a spreadsheet that simulates a well test.

The spreadsheet will cover the following charges from the contract, preparation, mobilization, standby, operational, personnel, and consumables. with discounts applied according to each bid.

Some general notes on contract evaluation are as follows.

- Exclusive or call out. Exclusive rental ensures that equipment under contract is secured for the agreed period and can be mobilized when required. Call-out rental, whereby a resource company only pays for equipment when mobilized, carries a significant risk with regard to availability. In a market with high demand for equipment, a call-out agreement provides no assurance that the contract equipment will be available when required. A resource company must consider this risk carefully before entering into such an arrangement.
- Synergies good or bad? Some contractors offer pooling of personnel for several services, thereby offering an apparent saving to the resource company. Both safety and quality can be undermined when personnel resources are overstretched. Offers along these lines do not always result in the benefits suggested.
- How well resourced are the contractors? Do they have dedicated quality control, logistics, and service personnel available locally? Many service contractors working in a busy international market fly personnel from one location to another to complement crew numbers. This practice works reasonably well if the personnel are experienced and if the working visa arrangements are flexible. But these conditions are not always present.

ALTERNATIVE PROPOSALS

Contractors may propose to provide their equipment and services under a completely different structure from that requested by the company. They may do so for a number of reasons, such as to win only those aspects of the contract that appeal to them most. In order to achieve eligibility to bid, a contractor may provide a pricing structure as per the company request, but with excessive pricing. Their competitive pricing may be offered under their alternative price proposals.

Award of Contract

The award of contract effectively means an agreement in writing to convert the contents of the bid into a binding contract. There is routinely a good deal of correspondence between the contractor and resource company at this stage to fine tune aspects of the contract, usually legal ones. In the interim a resource company may issue a letter of intent that is a conditional contract award subject to both parties arriving at agreement on any unresolved issues.

Request for Quotation

The contracts process is a lengthy one that requires considerable resources in expertise and time to accomplish. Circumstances do not always provide this time, and an alternative approach is required. A resource company may opt to invite well test service contractors to submit pricing for a service based on a request for quotation. A request for quotation is issued to service contractors whom the resource company has prequalified for health, safety, and environment as well as for technical competence. The process is therefore simpler, and the evaluation is based on a much shorter document.

A request for quotation document takes only the essential elements from the contracts process:

- Scope of work
- Scope of supply equipment and services
- Pricing structure
- Terms and conditions

RIG VISIT

In preparation for well testing, an engineer will visit a rig facility on land or offshore to inspect its suitability for well test operations. Such visits normally occur prior to the start of a new contract, usually while the rig is under contract to another resource company. Consent from the current contractor holder is necessary to carry out the visit, which is usually arranged through the drilling manager. Special inductions and training may be required prior to travel; for example, helicopter safety training and sea survival are routinely mandated for all personnel traveling to an offshore facility.

Such visits normally require a full day to complete and often involve an overnight stay on the facility. Because of the limited time available, it is useful to have a checklist to work from and a camera to help record details. A permit may be required to use the camera at the well site.

On arrival, all personnel must complete a safety orientation induction that involves a brief by a well site safety officer and a tour of the facility for familiarization with safety features. A visitor to the rig should introduce him- or herself to rig management and the resource company representatives on site. These individuals can provide useful information regarding the rig and advise on special issues associated with well test operations. Rig management may assign a senior member of the rig crew to assist in the visit.

Rig Visit Guideline

The object of a visit is to identify and record interfaces between the rig and the well test equipment. The following sections describe the activity of inspecting different areas of the rig in order to identify the interfaces specific to each.

Well test interfaces exist in relation to

- Deck placement
- Cranes
- Utilities
- Well test pipework
- Cooling system
- Facility pump systems
- King posts and flare booms
- Subsea
- Drill floor
- Fire-fighting capabilities
- Facility management systems

DECK PLACEMENT

Well test equipment occupies a great deal of space. At a land-based well site, this is not a difficult issue to manage since the overall space available is generally fairly large. Equipment can be located away from accommodation and work areas, and individual units can be separated for ease of access and to provide safe isolation from one another. Offshore, the story is different; space is a premium commodity and must be shared for other uses. Most offshore facilities assign a dedicated space to well testing based on deck strength, crane reach, and the proximity of personnel living quarters or work areas. The well test engineer must assess the area and consider its suitability for the proposed well test package. If the facility has tested previously, then layout drawings would exist to indicate previous equipment setups.

A suitable method for capturing information regarding deck placement is to make a layout drawing or sketch and mark any information of significance for the installation of well test equipment.

- Overall deck dimensions
- Deck load capacity
- Well test pipework, size, location, connection
- Spacing of deck beams
- Proximity of fire hydrants and alarms
- Location and type of utilities, phones, water, instrument air, and electrical power
- Access points to and from the well test area, in particular how these might be affected by the presence of well test equipment

CRANES

Every MODU facility uses deck cranes to transfer equipment and supplies between the MODU deck and supply vessels. Every item of well test equipment will be delivered to the facility on a supply vessel. For this reason it is important that the deck cranes are capable of lifting the well test equipment

weight and of placing that equipment into its allocated position, sometimes on the opposite side of the deck. A discussion with the barge engineer and crane operator is generally adequate to confirm this can be done. Some well tests involve exceptionally heavy loads in the form of high-capacity separators. A more rigorous heavy lift study may be required to verify crane suitability.

UTILITIES

The location of utilities, water, electrical power, and air supply points need to be identified and recorded.

Test equipment requires both single- and three-phase electrical power. The well test engineer liaises with the rig electrician to discuss these power supply needs, including the type, load, and location on deck in order to determine the distance to the nearest suitable supply point. The cabling interface is important. It should be established whether the facility can supply suitable end fittings or if these must be sourced by the contractor.

Pneumatic-driven devices are commonplace in the offshore environment; they provide a cheap, reliable, and safe alternative to electrically driven devices, which require hazardous class electric motors and insulation. Instrument air to drive pneumatic devices are available on almost every facility, the supply is normally hard piped from the motor room to numerous points around the facility. It is important to note what type of end fitting the facility fits to the pneumatic lines and whether the air is dry enough for each application. Condensed water in instrument air can damage air operated test equipment.

Seawater is used during equipment preparation for pressure testing, while potable water is utilized in boilers and engines for cooling.

WELL TEST PIPEWORK

Land-based rigs do not routinely supply well test pipework because the pipework routing is not torturous and can be assembled reasonably quickly by the well test contractor on site. By contrast, most MODU facilities provide some portion of the necessary pipework. This is due mainly to the time that would be required to install temporary pipework on a busy deck and around the various deck obstructions.

Preinstalled pipework might include some or all of the following:

- Standpipe
- High-pressure flow line
- Port and starboard oil, gas, air, vent, and water lines
- Flare booms and integral pipework

One of the objectives of the rig visit is to determine what pipework exists, its specifications and general condition. The well test service contractor must supply the balance of the pipework that is to interconnect the various items of well test equipment and to connect to the rig fixed pipework.

The standpipe is a high-pressure pipe standing vertically in the derrick about 10 to 12 m. During a well test, the top connection attaches to the production side of the flowhead using a flexible high-pressure hose to accommodate relative rig motion between the flowhead and the standpipe this type of movement only occurs on floating facilities. (see Figure 3.7).

The lower end of the standpipe terminates with a fitting at the drill floor level or, alternatively, continues down to the main deck to the assigned well test area. This arrangement varies on every facility according to the setup in the original rig design.

From the well test area some or all of the low-pressure pipework may be supplied to carry fluids from the well test area to each side of the rig where the flare booms will be located. These lines are designated for oil, gas, air, and gas vents.

COOLING SYSTEM

Heat radiation as a result of flaring represents a significant hazard that requires planning attention, particularly for high-rate oil well tests. Most MODU facilities supply some kind of cooling system — typically, a pipe following the handrail on each side of the rig, fitted with spray nozzles directed toward the direction of the flare. Seawater from one of the facility pump systems feeds the nozzles to create a water spray shield that absorbs heat radiation. This system must be assessed for its suitability to provide adequate cooling for the planned well test. Older facilities often have quite primitive setups that must be enhanced using a third-party contractor to supply additional cooling equipment and expertise. The rig visit must establish from the barge engineer or rig management the effectiveness of the existing cooling system, what pump feeds the supply, the maximum pump rate available, the date it was last used, and the type of well tests previously carried out.

FIGURE 4.1 Flare and cooling system. Photo by kind permission of Santos Limited, (Australia)

FACILITY PUMP SYSTEMS

A number of pump systems are common to every type of facility. For well test applications, each of these systems may have a different role to play. The systems can be distinguished as the rig mud pumps, cement unit, and general service or fire main. Mud pumps are large-capacity positive displacement pumps, controlled by the driller. Mud pumps intended for drilling use circulate fluid to the well during drilling activity. For a well test, these pumps take on a different role. One pump is assigned to control annulus pressure, which operates test tools, and one or more of the remaining pumps are assigned to provide seawater cooling to the flare boom. Alternatively, some facilities utilize the fire or general service pumps for cooling. These pumps generally cannot achieve the large volumes required for an oil well test.

The cement pump is a large-capacity positive displacement pump used for activities requiring precision control of volumes and pressure, for example, pumping cement and pressure testing. The cement pump (or cement unit, as it is often referred to) is part of a service provided by a dedicated cementing contractor. The cementing contractor is responsible for supplying and maintaining the cement unit, accessories, and cement chemicals. For well test-related activity, the cement unit can take fluids from the rig pit system and sometimes diesel from the motor room to supply kill fluid or underbalance fluid to the test string. The cement unit is also used for pressure testing and meter calibration. Note that handling diesel through the cement unit requires direct diesel feed to the pump suction.

Both the rig pumps and the cement unit have access to the rig floor via a common manifold. From the manifold, fluids are directed as required to the

Table 4.2 Pump Systems

Pump System	Drilling Use	Well Test Use	Controlled by
Mud Pumps	Circulate drilling fluid Pump kill fluid	Annulus pressure control Cooling system	Driller
Cement Pump	Cement operations Pressure testing	Pump kill fluid Pump underbalance Pressure testing Meter calibration	Cement Contractor
General Service and Fire Pumps	Fire system Water utilities	Fire system Water utilities Cooling system	Driller

kill line of the well test flowhead via standpipes, to the rig top drive, to the annulus choke and kill lines on the BOP, or to other lines dedicated for specific applications such as pressure testing surface equipment.

Kingposts and Flare Booms

At a land-based well site, flaring of hydrocarbons takes place using a flare pit that is positioned far from work areas. Other than a burner head to atomize liquid hydrocarbons no flare boom structure is required. The pipework connecting to the burner head runs along the ground from the well test equipment. Offshore, any well test involving the disposal of hydrocarbons by means of flaring will require at least one, but usually two, flare booms. Because these are not always provided in the scope of supply for the facility, the rig visit must establish a proposed location for the flare booms and the support structure or kingposts. The following points must be considered in relation to flare boom positioning.

- Deck strength
- Heat intensity due to flaring
- Crane access to flare booms
- Impact on other facility systems
- Distance from well test equipment

Because the installation of flare booms involves significant engineering and modification to the facility, a structural engineer must review the proposed location to evaluate its suitability and provide engineering drawings and installation procedures in accordance with the facility class certification. Any such engineering must have the approval of the facility owners. It will be evident from this discussion that flare boom installation requires substantial planning time in order to complete the necessary engineering, For this reason, many facilities provide flare booms as part of the scope of equipment supply. If already installed, the information to capture on the report is as follows

- Location
- Length
- Pipework details for each lines fitted for gas, oil, water, air andpilot gas.
- Certification status, both pipework and boom structure and rigging.

SUBSEA

For any floating exploration rig, a critical interface exists between the rig blowout preventer (BOP) and the well test string. The BOP is an important safety device capable of closing hydraulic rams at the seabed to provide a barrier between the well and the facility. The BOP also permits disconnection at the seabed to allow the facility to move off location at short notice in an

emergency. This feature is required as a contingency against a number of possible threats to the rig. A blowout or loss of well control occurs when the well starts to flow to surface and cannot be contained with drilling fluid. In order to contain the blowout, the driller operates a set of rams on the BOP, which will close to form a pressure-tight seal around the drill pipe. The internal bore of the pipe is more readily isolated at surface with the top drive or other manual well control valve. The BOP is also capable of cutting drill pipe to completely close off the well; this is achieved using a set of shear rams, sometimes called blind rams. The disconnect feature is located above the shear rams and permits the rig to move off location in an emergency. Emergencies are not exclusively well control related. Storm systems and ship collisions are possible situations that may require the rig to isolate the well and disconnect.

Given the importance of the BOP, the well test string must include features that do not compromise its emergency functions. The well test string must facilitate at least one set of BOP rams to form an annular seal on the test string. In addition, the test string should be capable of disconnect at the BOP to address the same emergency response capability as the BOP.

This interface becomes more complex on a DP vessel where the emergency response of the BOP is designed to operate rapidly, which in turn drives the response time for the disconnect feature of the test string.

During a rig visit, the subsea engineer can provide the information needed for the report. Information to include in the rig visit report is as follows:

- BOP type, size, and specification
- BOP ram size and configuration

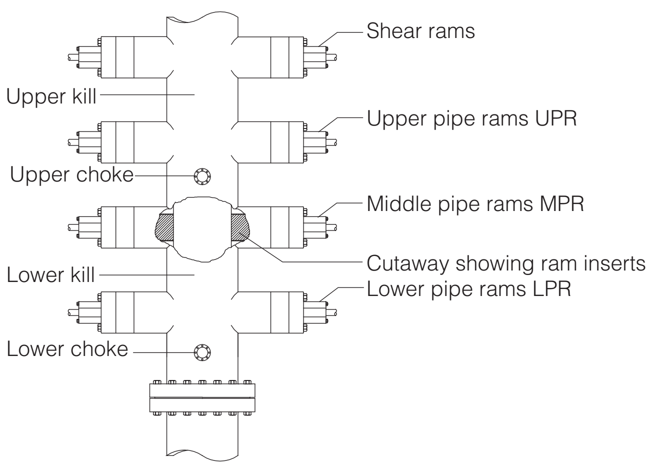


FIGURE 4.2 (a) BOP schematic

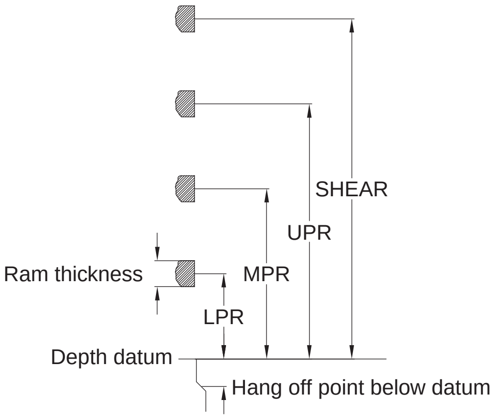


FIGURE 4.2 (b) Rig visit BOP data

- Depth datum
- Distance between each ram and the datum
- Location of choke and kill line access points below the rams
- Shear ram capability
- Temperature rating of ram inserts

The subsea engineer will also have drawings detailing much of the information listed above. This drawing will be included in the report.

DRILL FLOOR

This is an area of high activity where many potentially hazardous operations occur. The driller is responsible for everything that happens in and around the drill floor, and access may be restricted particularly during hazardous operations. Visitors to the facility must obtain permission from the driller before entering this area.

For a well test, many key operations take place or are controlled from the drill floor. Here the driller operates the derrick, which is needed to install the test string. The driller also operates the BOP and the mud pumps from the drill floor. Information needed for the rig visit report is as follows:

- Drill floor area and layout
- Quantity, size, and location of air winch tuggers, including manriders
- Height of fingers
- Orientation of draw-works running tracks in relation to the vee door
- Production and kill standpipe details, including elevation of inlet connections
- Top drive connection
- Block travel, that is, travel distance from rotary table to crown block.

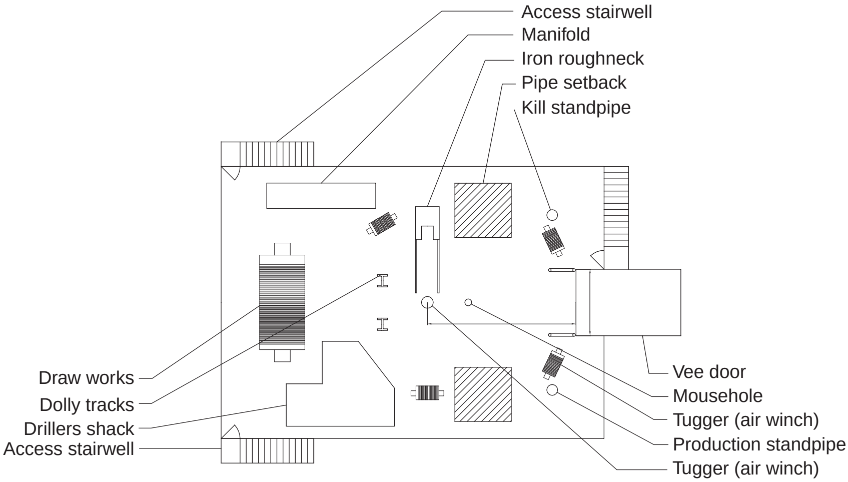


FIGURE 4.3 Drill floor layout

The layout of the drill floor is useful for planning test equipment location and preparing handling procedures for complex lifts (i.e., long subassemblies and the flowhead assembly). The location and type of air winches available contribute to subassembly handling procedures.

The height of the fingers can be important in order to plan the length for assemblies to rack in the derrick. Some drill floor designs orientate the block running tracks, sometimes referred to as dolly tracks, perpendicular to the vee door rather than opposite the vee door.

Block travel, that is, the distance the blocks can travel from the rotary to the top of the derrick, can restrict the spaceout for the well test string. Some rigs have limited block travel of the order of ~35 m. This limits the flexibility for combining stick up, long bails for pressure control equipment, and spare block travel to accommodate string movement required for certain packer types and for subsea spaceout.

FIRE-FIGHTING CAPABILITIES

Every drilling facility, both land based and offshore, is equipped with fire-fighting capabilities suited to drilling operations. Fire plans provide details of the existing arrangement, including location and type of fire-fighting equipment, that is, deluge systems, fire monitors, hydrants, extinguishers, special chemicals, fire suits, muster stations, alarms, communications systems, and emergency fire pump location. The fire plan includes a schematic identifying all of the above information. Many drilling facilities consider the location of well test equipment in their plans and often provide specialized well test fire-fighting capability. such as dedicated deluge systems. However, this is not always the case, and the well test engineer must note what systems are available that might be required in a revision of the fire plan to include well test equipment. For

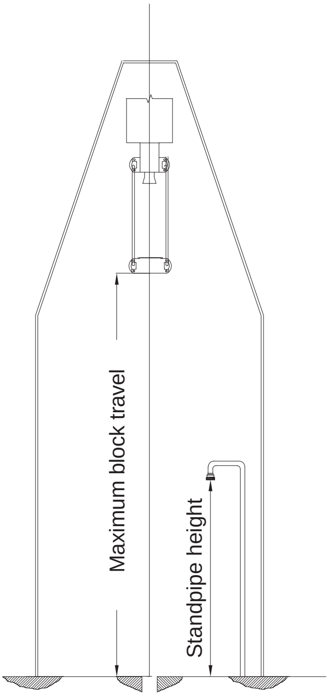


FIGURE 4.4 Important derrick dimensions

example, there might be few fire hydrants or monitors in the area proposed for the well test equipment location. Fire and escape plans developed for the well test must consider escape routes and the impact on existing facility safety equipment. The location of tanks containing hydrocarbon inventory and pipework routing must consider the potential for fire and explosion and how such events might impede escape routes, muster stations, lifeboats, communications equipment, and so on. During the rig visit, the well test engineer should discuss these issues with facility management and seek advice on how best to develop a fire plan for the well test. Chapter 6 includes further discussion on well test fire and explosion, and a sample well test fire plan is provided in the appendices.

FACILITY MANAGEMENT SYSTEMS

Facility management systems are processes used to manage safety on the facility. Inherent in the management of safety is the process whereby facility managers and supervisors communicate operational issues to the crew, to inform personnel of specific tasks and to raise awareness of the hazards associated with each task. The following list identifies some of the processes frequently utilized for this purpose.

- Facility orientation and company inductions
- Pre-tour and contractor safety meetings

- Emergency drills
- Pre-task discussions, JSA, Toolbox, other
- Safety reporting systems, STOP, START, other
- Permit to work
- Third-party equipment acceptance procedures
- Well test specific procedures
- On-site personnel training

A detailed description of safety management processes is presented in Chapter 6. With regard to the rig visit report, the well test engineer will identify the processes in use by the facility and take copies of forms or other special procedures the facility might have in relation to the well test, so that these may be incorporated into detailed planning.

LOGISTICS PLAN

Moving personnel and large amounts of equipment to and from a well site requires a great deal of resources and coordination. Equipment travels by road, air and sea from contractor bases across the country and sometimes overseas. Similarly, contractor personnel often travel from overseas for well test operations. A logistics plan details the controls put in place to coordinate this effort. Not every organization develops a plan specifically for well testing. Sometimes well test planning is incorporated into an overall logistics plan. The following headings outline a typical plan. A sample logistics plan is also provided in the appendices.

Logistics Management Structure

The logistics management structure defines the roles within the resource company organization that are responsible for coordinating the movement of equipment and personnel in relation to the well test operation. This information may be presented using an organigram. A typical setup defines a lead logistics superintendent based at the resource company headquarters or supply base and a second logistics coordinator based at the well site or, if offshore, on the facility. These personnel represent the focal points within the resource company organization through which all material and personnel movements are authorized and coordinated. These roles generally organize all transportation, and only by special arrangement do contractors arrange transport for equipment.

Personnel movements are generally managed through the well site logistics coordinator who arranges flights and accommodation for personnel traveling to and from the well site.

This section of the plan lists the names and contact details of the logistics focal points together with delivery addresses for all equipment and material deliveries. Location maps for land-based well sites, particularly road maps

detailing appropriate waypoints if the well site is in a remote location, are important for personnel who have occasion to travel to the well site by road.

Scheduling

Activities on the facility prior to the well test are subject to change. During the period that the well test planning team is preparing for the well test, the facility may be drilling for the resource company or be still on contract elsewhere. Problems frequently occur during the drilling process that may set the schedule back from hours to days. There may be uncertainties in the schedule because other resource companies might base their forward plans on the success of drilling. Side track, coring, and well testing may be planned, all of which could set the schedule back weeks. Adverse weather and mechanical problems might also add to delays. The drilling department manager maintains contact with the facility manager and its current resource company client in order to track the schedule.

Given the number of contractors involved with well test activity, and given that many, if not all, of these contractors do not have representation inside the resource company organization; it is important that they be kept informed of the operational schedule as it changes. Without this notice, contractors cannot plan equipment and personnel availability. Most resource companies issue periodic schedule updates to all contractors through the well site logistics coordinator. The well test engineer must ensure that the logistics coordinator has a comprehensive contractor list (i.e., one that is inclusive of all well test service contractors) and that the appropriate focal point within each contractor organization is represented.

The logistics plan details the focal point for issuing periodic schedules and any flags or milestones that trigger logistics movements. Many resource companies plan mobilization of contractor equipment based on achieving drilling milestones.

Contractor Responsibilities

Resource companies define contractor responsibilities to communicate contractual, regulatory, and facility-specific requirements in relation to the movement of personnel and equipment. Provided the contract preparation was thorough, most of these points will have been addressed in the scope of supply and the terms and conditions. Whether or not this is the case, it is useful to itemize logistics requirements here so that the information is ready at hand for the benefit of operational personnel. The personnel preparing and loading the equipment will not have had access to the contract, nor would it be wise to assume that contractor managers will disseminate this information down to the workshops and field locations. Examples of the responsibilities defined in a typical plan are as follows.

Personnel

- Personnel shall comply with company drug and alcohol policies.
- Contractors shall be responsible to ensure personnel traveling from overseas have appropriate work visas.
- Personnel must carry their own personal protective equipment PPE.
- Personnel traveling to an offshore facility by helicopter will have received appropriate safety training.

Equipment

- Equipment shall be secure and transported inside baskets, containers, or skids with dedicated lifting slings that comply with the resource company's lifting standards.
- Lifting certification shall accompany all lifts.
- Dangerous goods shall be marked in accordance with International Air Transport Authority IATA regulations and supported with appropriate paperwork.
- Contractors shall supply complete manifests indicating the weights and dimensions for every lift.

The details for the plan are developed internally by the planning team, and the document is prepared by the logistics superintendent, with input for well test aspects provided by the well test engineer. Alternatively, the well test engineer might prepare a separate well test logistics plan that would stand separate from that used for drilling. The logistics plan is a controlled document.

ROLES AND RESPONSIBILITIES

Roles and responsibilities serve a number of purposes, first and foremost that of delegating specific tasks to individuals in respect of

- Decision making
- Reporting
- Supervision
- Work

Second, in doing so, clearly defined roles and responsibilities ensure every aspect for the management of the operation is identified and assigned, thereby contributing to the overall control of the well test.

Roles and responsibilities are not static. Every well test is different, and the set of activities that make up each task and the order and manner in which tasks are executed change with each well test program. Individuals involved with the well test may be experienced, However, frequently they may find themselves engaged in new or changed tasks due to revised or new procedures that derive from changes in practices, new technologies, and modifications in regulations.

Roles and responsibilities are often listed in a separate section of the well test program. The individuals identified are managers, supervisors, and

specialists within the resource company and all of the contractors connected with the well test. The roles and responsibilities derive from discussions with contractors during detailed planning, from the contract scope of work, from the terms and conditions, and from responsibilities defined in regulations.

Following is a sample set of roles and responsibilities for a well test engineer. At the well site the well test engineer shall

- Report directly to the well site drilling supervisor.
- Oversee the implementation of all aspects of the Safety Case in respect of the well test operation.
- Be responsible for supervising the execution of the well test program.
- Act as technical adviser to the well site drilling supervisor and subsurface engineer.
- Monitor operations and plan ahead in order to ensure seamless changeover between tasks.
- Supervise service contractors and act as the liaison between the resource company and service contractor organizations.
- Calculate fluid volumes, tallies, spaceouts, and hydrostatic pressures.
- Collate contractor well test reports, data, and samples and present summary reports to the drilling supervisor for distribution.

DETAILED PLANNING AND THE WELL TEST PROGRAM

The Basis for Design provides an outline of the well test procedure, listing the services required and providing a brief outline as to how those services will be applied. Subsequent to the contracts process, detailed planning commences, building on the information outlined in the Basis for Design. The resource company, with the well test engineer acting as its focal point, establishes contact with each of the contractor focal points to arrange meetings and establish correspondence on planning issues. Contractors might challenge aspects of the proposed well test plan and propose alternatives. Meetings between groups of contractors and resource company representatives often take place to resolve difficult design issues. The planning team evaluates all inputs based on a risk assessment approach, in relation not only to safety, but also to technical merit, reliability, accuracy, efficiency, and cost. During the course of detailed planning, issues may arise that require contractors to supply equipment and services outside the scope of supply agreed to in the contract. In these instances, a contract variation may be required to address the change in scope. A contract variation does not require a reissue of the contract but forms an addendum to the existing contract. A variation generally needs only to detail the technical and financial change in scope but can otherwise refer to the existing contract for terms and conditions. The well test engineer gathers contractor-specific procedures and collates the information into a single document that provides procedures and technical reference for every step of the well test operation. This document is the well test program described in detail in Chapter 7.

TEST THE WELL ON PAPER

Prior to the operation, many resource companies perform a desktop exercise referred to as a test the well on paper exercise (TWOP for short). Its purpose is to thoroughly review the program in order to identify omissions and mistakes. Given that most participants during the course of detailed planning may only have contributed in respect of their own areas of expertise, the TWOP provides an opportunity for all parties to assess the overall procedure.

The well test engineer is responsible for coordinating the TWOP exercise. Representatives from all contractor organizations involved with the well test, including the facility owners, are invited to attend. In order to add the most value, field personnel are invited in preference to office-based personnel. Well site managers, drillers, supervisors, and tools specialists can provide greater value to such an exercise than desk engineers and specialists who spend little time at the well site.

Attendees read through the program steps from start to finish. All are invited to comment on any aspect of the program, good or bad. Each point is discussed or noted for later discussion if it involves further detailed analysis.

The output from a TWOP exercise is a finalized revision to the Well Test Program, which is subsequently distributed to all parties through document control.

WELL TEST VALIDATION

The resource company plans the well test making decisions with regard to the well test design and procedures, while contractors provide input in the form of technical advice and recommendations. This plan is reviewed internally following the document control review process and using risk assessments and the TWOP process. A well test validation is a process whereby the well test design is reviewed by an independent competent third party. In some states, such a review is mandated by regulation. The well test engineer generally coordinates this process. The following set of steps illustrates a typical well test validation process in a regulatory environment where such a process is mandated

The resource company details a scope of work consistent with that demanded by regulations. A typical scope of work entails a review of the following

1. Well test design report
2. Fire and escape plans
3. Layout, hazardous areas, and the piping and instrumentation diagrams
4. Equipment maintenance and certification records
5. Risk assessments
6. Well test program
7. The resource company engages a competent person or organization, qualified to conduct the assessment. This is usually an independent well test engineer or organization specializing in providing well test engineering planning support.

8. The resource company submits a proposal to the regulator detailing the scope of validation and the intended validation engineer.
9. The regulator issues an approval based on the proposal
10. The documents, when prepared, are submitted to the validation engineer for review.
11. The validation engineer issues findings based on the review, some of which may require attention to address any planning shortfalls or concerns.
12. Once the validation engineer is satisfied that the design is fit for purpose, he or she issues a statement to that effect. Support is provided by a report detailing the results of the validation exercise.

SAFETY PLANNING

Management of safety is the single most important aspect of well test planning. Omitting or neglecting safety in planning may result in serious risk to personnel. For this reason safety must be embedded into every aspect of well test planning, that is, management processes, operational procedures, and engineering.

Most regulatory environments require a formal safety assessment for any well test operation supported by appropriate documentation. The Safety Case is a widely accepted safety management regime. Under the Safety Case, resource companies must demonstrate that the hazards associated with the operation have been assessed to a standard using formal assessment processes and that adequate safeguard controls have been implemented to reduce risk to acceptable levels, or ALARP (as low as reasonably practicable).

Inputs to safety are provided by different stakeholders to address different aspects of the Safety Case. Table 4.3 summarizes this information.

Table 4.3 Safety Case Overview

Area of Control	Document	Responsibility
MODU Facility Resource Company Management Systems Integration	Vessel Safety Case Resource Company Drilling department Safety Case Addendum	Facility Owner Drilling Department HSE Department Management
Well Specific Hazard Integration to the Safety Case	Resource Company Drilling department Safety Case Addendum	Drilling Department HSE Department Management
Well Test Integration to the Safety Case	Resource Company Well Test Safety Case Addendum	Well Test Engineer HSE Department Management

A Vessel Safety Case details the management of safety in relation to the facility's routine operations. A resource company Safety Case Addendum is added to the vessel safety case to align differences in the safety management systems between the facility owner and the resource company and to address issues specific to the resource company's well site activity. This addendum is valid only for the period of the contract between the resource company and the facility owner. A well test addendum to the Safety Case addresses issues of integration for the well test operation and how that operation impacts the existing Vessel Safety Case. The structure of the document in each of the above is similar: a facility description, a description of the safety management systems, and a formal safety assessment.

The well test engineer plays a central role in compiling the Safety Case Addendum, which pertains to the well test.

Given the importance and scope of this topic, Chapter 6 is devoted entirely to the process of planning for safety.

Chapter | five

Engineered Controls

CHAPTER CONTENTS

Every variable from pressure, temperature, fluid type, and well depth to logistics and metocean conditions requires control; an uncontrolled variable represents risk to the successful outcome of the well test. A control is a physical barrier, a device or a process that acts to constrain or direct the effects of a variable. There are only two types, engineered and procedural controls, and collectively they make up the well test design. Once in place, engineered controls physically eliminate or contain hazards associated with a particular variable. They do not require human intervention to be effective and are therefore more reliable than procedural controls. The purpose of this chapter is to describe common well test engineering controls and the processes behind their selection.

The order in which topics are presented here does not necessarily follow the order in which issues would be tackled and resolved during planning. Instead the order follows a learning progression, and information in the first section is used and referenced in later sections.

- Fluids
- Materials
- Erosion
- Pipework Sizing
- Nodal Analysis
- Tubing Stress Analysis
- Hazard and Operability
- Rig Interface Engineering
- Facility Design and Engineering Report
- Design Review

FLUIDS

Fluids are used primarily to control well pressure, but they also perform a number of other tasks depending on the operation. The type of fluid also varies according to the operation. When drilling, mud provides a pressure barrier to the reservoir, carries cuttings clear of the drill bit and back to surface, and

maintains borehole stability. It also transmits logging while drilling LWD signals and drives downhole motors for directional drilling. Drilling mud contains various ingredients to perform these tasks, bridging agents help to stop fluid loss into the formation, dissolved solids adjust the weight of the fluid, and thickeners adjust viscosity and provide mechanical strength to help support the wellbore. During the drilling operation, this mud is in constant motion, travelling down the drill string and up the annular space outside the drill string back to the rig where it is filtered and conditioned for reuse.

In a well test, fluid in the annulus, between the test string and the production casing, is static for the entire period of the test. It undergoes pressure cycling as annulus-operated tools are opened and closed, and it is subject to changes in temperature, heating during production, and cooling during shut-in or when pumping fluids into the test string. Drilling mud, whether water or oil based, is not intended for this application. Under static conditions, there is a potential for dissolved barite solids to come out of solution, and if static for extended periods or at elevated temperatures. This solids dropout can become severe to the point that they compact above the packer and in tool operating mechanisms. The consequences may include inability to operate downhole tools and may result in premature termination of the well test. Solids dropout might also result with difficulties in retrieving some packers due to compaction above the elements. Drilling mud is compressible and therefore not ideally suited for transmitting pressure signals over the length of the well to downhole tools, many of which require multiple and sometimes precise pressure signals in order to cycle correctly. These problems vary according to prevailing conditions. As mud weight increases to achieve greater hydrostatic pressures for well control purposes, the solids content in the mud also increases and results in potentially greater volumes of solids dropout. As the well temperature increases, the problems associated with changes in mud properties become more pronounced.

Brine provides an alternative fluid for testing applications. Brine is basically water with dissolved salt to provide the desired weight. Brine has certain advantages for well test applications: it is stable even at high temperatures, and it is practically incompressible and therefore suited for transmitting annulus pressure signals to downhole tools.

Unfortunately, brine is entirely unsuited to drilling because it has none of the bridging agents that help prevent fluid loss to the formation. Nor does brine contribute to wellbore stability, with the result that for many well tests, the drilling mud system must be changed to a brine test fluid. The disadvantages include the cost of a second fluid system, the cost associated with the time needed to change out the fluids, the resources required to manage the logistics at the well site or shore base facility on the supply vessels and at the rig, together with the resources required to clean pit systems and supply vessel storage tanks to avoid contamination. All of these must be co-ordinated so that the well is ready to receive the change-out in fluids without

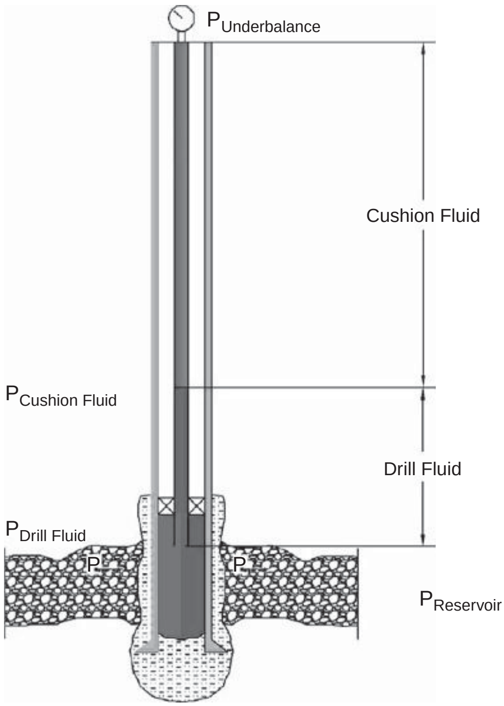
compromising well barriers or formation damage and with minimal impact on critical path time. A decision to use brine as a test fluid is a significant one and is assessed on a case-by-case basis, sometimes directed by company policy, by the logistics involved, or by well conditions.

Underbalance

Underbalance fluids facilitate the controlled production of reservoir fluid to surface. An underbalance pressure is created when heavy kill weight fluid in the tubing, mud, or brine is displaced with a lighter underbalance fluid, sometimes referred to as cushion fluid. The underbalance pressure is the differential measured at surface between the hydrostatic weight of the well fluid and the pressure in the reservoir. The magnitude of the underbalance pressure is varied by altering the amount of fluid displaced and selecting the type of underbalance fluid.

Selecting the optimum underbalance pressure is a decision that must involve the subsurface team, considering the conditions of skin, fluid loss to the formation, permeability, and the potential for sand production. An inadequate underbalance may fail to overcome the resistance to flow presented by skin effects and fluid losses. Skin is a layer of low permeability in the near wellbore area caused by the drilling process. Drilling can damage the formation face, while drilling mud penetrates the formation rock to varying degrees. Solids in the mud act as bridging agents that become embedded in the rock pores producing a low permeability skin at the formation face (see Figure 2.1). Other than the effect of skin, drilling mud may have penetrated some distance into the formation. This fluid loss to the formation can be significant and may vary from tens to thousands of barrels. When attempting to flow the well later, much of this heavy fluid may produce back into the wellbore, along with, or instead of, reservoir hydrocarbons. In some instances, enough heavy fluid may be produced in the wellbore to stop production, and in such cases it may be necessary to repeat the underbalance operation in order to recover enough drilling fluid to allow the reservoir fluids to produce.

Excessive underbalance may result in formation damage, including failure of the sand face, which can lead to sand production. An unconsolidated formation is one in which the particles that make up the rock material are loosely bound to one another and can, given the right conditions, separate from the formation as sand. The subsurface team evaluates formation rock strength data from cores and logs in order to determine the likelihood for this to occur. Lab testing of cores is often performed to simulate production conditions to better assess the initial conditions. If the reservoir pressure is at or near the fluid bubble point pressure (i.e. the pressure at and below which solution gas separates from oil), this may result with higher than expected gas production and could affect the way the drawdown develops.



$$P_{Underbalance} = P_{Reservoir} - (P_{Cushion\ Fluid} + P_{Drill\ Fluid})$$

FIGURE 5.1 Underbalance pressure

Diesel, oil base mud, and nitrogen are common underbalance fluids. The selection of the fluid has consequences for the design of the test other than its effect on the reservoir. These fluids may require specialized services and handling procedures for pumping or disposal. Diesel is a common choice. With a low specific gravity, it can provide a wide range of underbalance pressures, depending on the volume displaced to the test string. It is conveniently available on every drilling facility and does not require additional contractor services. The cement unit also available at all drilling facilities can readily deliver diesel to the test string, and because it is flammable, diesel is easy to dispose of at the flare.

With the example illustrated in Figure 5.2, a diesel cushion is displaced to a depth of 2,700 m, just above the circulating valve. The underbalance provided can be calculated as shown.

In some parts of the world where regulations restrict the use of diesel or prohibit flaring, alternative fluids must be used. Nitrogen gas offers an alternative capable of greater underbalance pressures and is environmentally friendly. Nitrogen is transported as a liquid and pumped as a gas. The handling procedures differ significantly from diesel, and a dedicated nitrogen

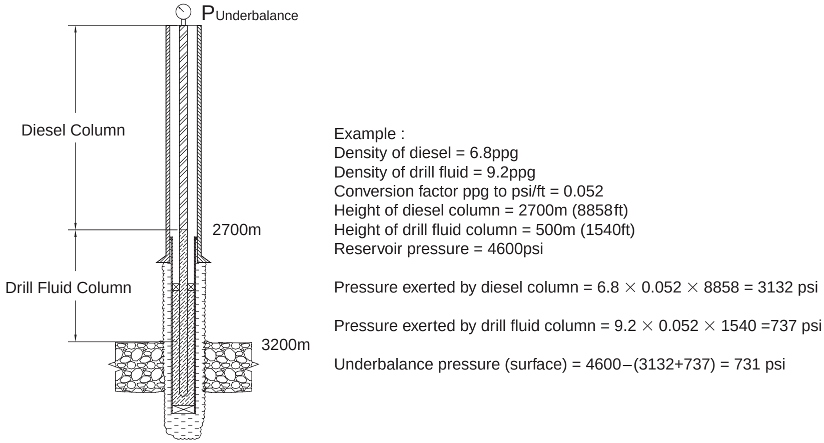


FIGURE 5.2 Underbalance pressure example

service contractor is required to supply personnel and equipment, including liquid nitrogen tanks, a converter/pump unit, and workshop. All of this entails additional cost, handling, and deck space. (Refer to Figure 2.18 for a nitrogen system setup.)

The calculation for the hydrostatic pressure exerted by the nitrogen column is complicated by the fact that nitrogen is compressible and therefore does not keep a linear pressure gradient. A precise calculation can be obtained using tables and formulas available from the nitrogen service contractor.

MATERIALS

The materials and the equipment assemblies provided by contractors and suppliers are delivered with specifications that detail design limitations — for example, yield strength, load capacity, safe working pressure, and safe operating temperature range. For new or recently surveyed materials and equipment, it may be reasonable to expect that it will perform to specifications. In many instances, however, operating materials and equipment at or near its maximum safe design limits is not always advisable. To take an example, consider a test separator. Perhaps as many as four years since its last major survey, in the intervening period, this separator will have performed a number of well test operations, travelling to and from different well sites and exposed to a range of well test environments. After each operation, the contractor will have performed routine service work to maintain the equipment. However, contractor processes are fallible, as are the service personnel following those processes. Despite detailed procedures, maintenance systems audits, and equipment inspections, details are often overlooked. To illustrate, suppose the wrong seal material is used during assembly of one of the separator valves. It is likely that the seal would hold pressure during the normal

workshop and well site hydro test, but may subsequently fail in operation at high temperature. This is not to say that equipment supplied by contractors should be considered unreliable, but any equipment such as a separator rated to operate at certain conditions will reliably perform only at these conditions, provided every single component (i.e., valves, seals, flanges, instrumentation, pipework, and the vessel itself) is fully serviced according to the manufacturer's and contractors procedures. In a perfect world, it would be maintained fully in accordance with the manufacturing specifications. In practice, this may not be the case, and it is a reasonable precaution when selecting materials and equipment to suit a particular set of environmental conditions that some margin of safety is built into the selection so that it will not be operating at or near design limits. The same is no less true for the materials and equipment supplied by the facility owner, rig-supplied pipework, deck spaces, and so on. The facility specifications are discussed in the Rig Engineering Interfaces section of this chapter.

Elastomers

Elastomers are widely used for seal and gasket materials; contractors assemble equipment using different elastomers suited to the conditions defined in the Basis for Design. A range of synthetic polymers are produced by contractors and suppliers of elastomers to make o-rings, packer elements, pipe seals, valve seals, gaskets, and hose material. Each has properties that suit it to a particular set of conditions. Some of those properties include resistance to chemical deterioration through contact with petroleum, hydrogen sulphide, carbon dioxide, and other fluids. Other properties include abrasion resistance, explosive decompression resistance, and a low friction coefficient required for dynamic seals.

For high-pressure applications, hard material seals have better anti-extrusion properties, but with high temperatures some seals soften and become more prone to extrusion, so material selection needs to consider how the anti-extrusion resistance changes with temperature.

Generic synthetic polymers include Nitrile (NBR), Hydrogenated Nitrile (HNBR), Flouroelastomers (FKM), Tetrafluoroethylene Propylene (FEPM), and Perfluoroelastomers (FFKM). Manufacturers develop variants of these to produce polymers with specific properties for specialized applications. Such formulations have their own proprietary names.

The well test engineer provides details of the expected fluids and conditions in the Basis for Design document. Using this document, contractors select appropriate elastomers for the equipment within their scope of supply. Technical documentation provided by the contractor as part of their package preparation includes elastomer type and specifications. Elastomer selection for well tests involving extreme or hostile conditions requires close scrutiny and may require input from materials specialists and, in some cases, lab testing.

Metal Alloys

Surfaces exposed to the well fluid environment and in particular flow-wetted surfaces (i.e., those surfaces in contact with producing fluids) may suffer rapid corrosion deterioration through chemical attack or erosion through mechanical wear. A corrosion-resistant alloy (CRA) is a material that resists these effects and can be used in casing, tubing, downhole tools, surface pipe-work, manifolds, valves, and flanges. With increasingly hostile well environments, use of more exotic and expensive CRAs is necessary. In a more benign environment, the exposure time for materials used in a well test is short compared to a production environment. For this reason the more exotic alloys are generally not required. However, in more hostile conditions at extremes of temperature or high concentrations of carbon dioxide or H_2S, material suitability must be assessed when selecting equipment for the test because of the risk of corrosion failure, also called environmentally assisted cracking (EAC). EAC refers to a number of corrosion processes that share specific characteristics and that can occur during a well test. Corrosion occurs rapidly in materials exposed to the right environmental conditions and results in metal embrittlement. Sulphide and chloride stress cracking are examples of environmentally assisted cracking that can occur during the well test.

Sulphide stress cracking (SSC) is a form of corrosion that attacks metals under stress. When present with water, a reaction takes place that forms cracks and hardening of the material, rendering the metal susceptible to failure. This effect of the chemical reaction is metal embrittlement or hardening. Higher strength materials are at greater risk to sulphide stress cracking due to the higher internal stresses within the material.

The common materials reference standard NACE MR-01-75 identifies a number of factors that contribute to the corrosion of carbon and low-alloy steels in H_2S environments; among them are the following.

1. Chemical composition, method of manufacture, strength, hardness, amount of cold work, and heat treatment condition
2. Hydrogen sulphide concentration
3. Acidity or pH of the water phase
4. Presence of sulphur or other oxidants
5. Tensile stress
6. Temperatures
7. Exposure duration

Because softer metals are more resistant to SSC, hardness is often used as a measure of SSC resistance. Chloride stress cracking, like sulphide stress cracking, occurs on tubing under tensile stress and affects steels in a similar manner, resulting in metal embrittlement. Chlorides can be present at high concentrations in drilling fluids and formation water.

Hydrogen Sulphide Concentrations

Hydrogen sulphide is measured in parts per million. Low concentrations at low pressures present an insignificant threat of damage to equipment, but as concentrations increase and as gas pressure increases, the effects of H_2S present in the gas become significant. This partial pressure exerted by the H_2S component of the gas is an important feature for material selection. The reference standard NACE MR-01-75 designated H_2S or sour service environment as a petroleum gas phase, with an H_2S partial pressure of greater than 0.05 psia and a total pressure greater than 65 psia or an H_2S concentration greater than 150,000 ppm.

In a well test environment where there are uncertainties regarding fluid makeup, it is not practical to design a system to remove chlorides or hydrogen sulphide before it passes through process equipment. Instead, materials are selected on the basis of their resistance to failure in the presence of these corrosive agents under flowing conditions.

It is not possible to predict the exact nature of the fluids to which well test equipment will be exposed, even if exposure periods are short compared with production equipment. Well test equipment is used in uncertain and varying environments, with the result that most well test equipment is manufactured with H_2S corrosion resistant materials as standard. When planning a well test for a known sour environment, the well test engineer must include controls to ensure that all materials with a potential exposure to production fluids are in accordance with the materials standards. Such controls exist in the equipment certification inspections and the design verification process.

Erosion

Pipework and equipment erosion can occur during well test activity and may result in leaks that have the potential to escalate into fire and explosion events.

Four general mechanisms can contribute to erosion.

- Particulate erosion
- Liquid droplet erosion
- Erosion-corrosion
- Cavitation

The conditions giving rise to these erosion mechanisms are dependent on flowing conditions in particular fluid velocity and the fluid medium, liquid or gas. In a well test setup, these conditions are most severe at chokes, elbows, check valves, throttling valves, flow restrictors, and pipe reducers. Since most pipework and valve materials are manufactured from carbon steel, except for some components where greater resistance to erosion is essential, controls are necessary to manage erosion hazards. Choke inserts are generally manufactured from tungsten carbide and some throttling valve internals of stainless steel.

These materials have greater resistance to erosion but still frequently experience erosion damage under the right conditions.

The most common and generally the most serious form of erosion occurs when solid particles such as sand, suspended in rapidly moving gas, impinge onto pipework surfaces, causing pits and cratering that reduce the wall thickness of the pipe. The angle at which the particles impinge on the surface significantly influences the effect. Direct impingement is less severe than high angles; very little particulate erosion occurs in straight pipe where the flow is essentially parallel to the inner pipe surface. As a result, erosion occurs at elbows and reducers more so than in straight pipes or tee junctions, where the solid particles strike the pipe walls at angles.

The likelihood for sand production is at its highest during the initial cleanup and after choke changes. Gas well tests present the greatest risk because the velocities inside the pipework are high and because solid particles are not carried with the gas around bends or turns within the flow stream but instead, owing to their greater mass and the low viscosity of gas, tend to travel in straight lines through the gas and impinge on internal pipe surfaces. Slugging can have the same effect as choke changes. Sand can accumulate at low points during stable flow but produce in greater quantities and at the higher velocities if flow slugging occurs (i.e., periodic and unpredictable production at higher than expected rates).

Small solid particles <10 microns carried with the produced fluid contribute little to particulate erosion. Very large solid particles >1 mm are slower moving and tend to settle at low points and also contribute little to erosion. However, their accumulation may cause other production problems if produced in sufficient volumes. Particles in the size range 50–100 microns represent a typical size distribution in unconsolidated sand. Their abrasiveness, or ability to cause erosion, is dependent not only on their size and velocity but also on their hardness and shape, sharp-edged particles being more abrasive.

Although the relative material softness in elastomers will absorb some of the impact energy, elastomers used in pipe and valve seals are often very susceptible to erosion by the same mechanisms as steel pipe. The other erosion mechanisms listed at the start of this section contribute less to erosion during well test activity. Brief descriptions of these mechanisms are included in the glossary.

Solids control depends to a large extent on the degree of understanding of the subsurface team as to the nature of the solids and the likelihood for solids production. Without some guidance on size distribution and quantity, it can be difficult to design effective controls. Studies based on core data provide information on likely solids production and on the particle geometry and size distribution. Offset data and experience from similar operations also provide valuable data.

It is the task of the well test engineer and the planning team to develop an erosion management plan that will include a combination of some or all of the following controls.

1. Pipework design, sizing, and velocity control
2. Sand screens, filters, and sand separators
3. Sand and erosion monitoring

Pipe-sizing calculations use inputs provided from tools such as nodal analysis to show the relationship between production rate and fluid velocities and pressures for a range of different pipe sizes. The program may be written so as to avoid production rates where erosion velocities occur or to limit the flow duration at these rates and thereby reduce the erosion risk. Where the test objectives mandate high production rates, large-bore pipes may be utilized to reduce the fluid velocity, thus providing an engineered solution to the problem.

Physically filtering sand downhole or at surface is also possible. Downhole screens (Figure 5.3) are in essence perforated tubing joints wrapped with wire and form a mesh to provide a filter, sized to suit the expected solids.

In the case of severe sand production, more sophisticated downhole sand exclusion is required.

A gravel pack (see Figure 5.4) entails packing off the wellbore area using specially sized gravel beads, which provide wellbore support as well as solids filtration. Such systems require considerable planning lead time.

Surface-located sand filtration equipment has the advantage of being readily accessible for inspection, sampling, and sand removal, but does not prevent the inflow of sand downhole, which may cause production problems within

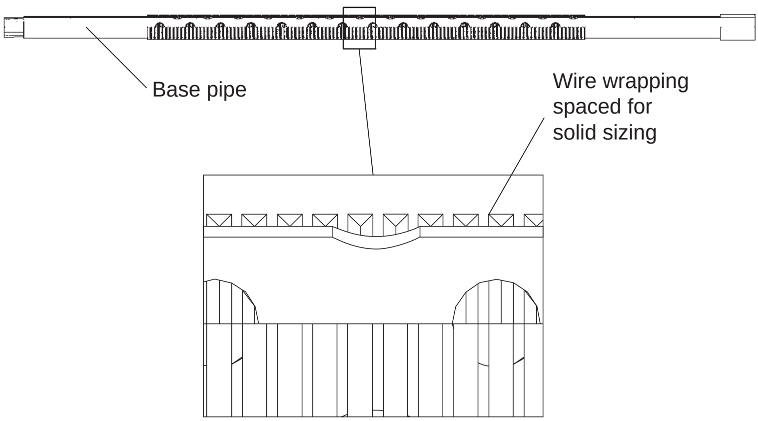


FIGURE 5.3 Sand screen

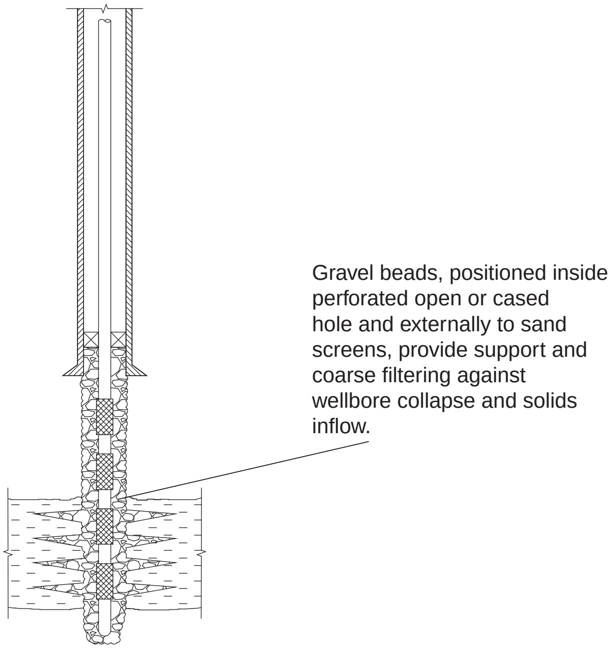


FIGURE 5.4 Gravel pack

the well. Sand filters situated before the well test choke manifold protect the surface equipment downstream of the filter. See Figure 5.5.

Sand separators (Figure 5.6) encompass a number of different designs. Some simply consist of large vessels situated before the separator and rely on the drop in the velocity of fluid entering the vessel to cause solids dropout, and others are fitted with internal devices such as cyclonic centrifuges to assist with solids separation.

Sand separators are not routinely supplied in a well test equipment package, but can be made available from the surface well test contractor with adequate planning notice.

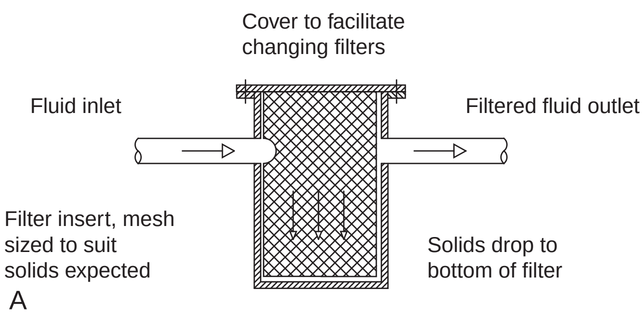


FIGURE 5.5 (a) Surface sand filter

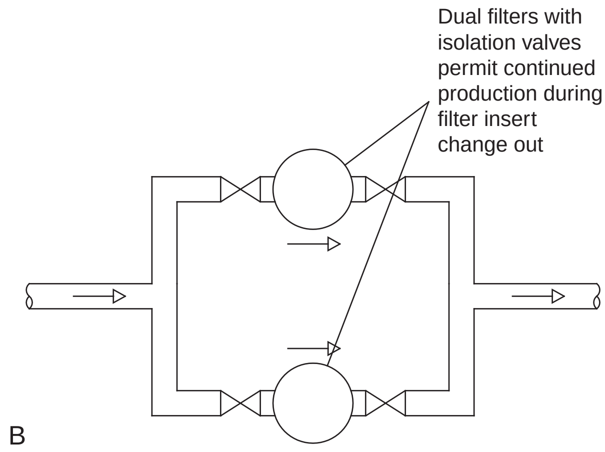


FIGURE 5.5 (b) Dual pot sand filter schematic

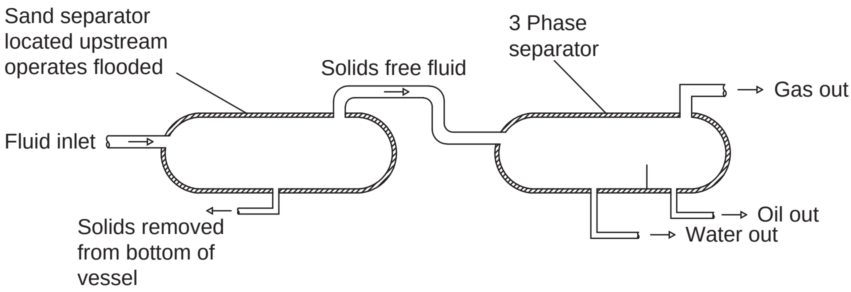


FIGURE 5.6 Sand separator

Erosion monitoring is a safeguard that provides an early indication of sand production and possible erosion. Common monitoring techniques include

- Direct measurement using BSW samples
- Pipework thickness monitoring
- Erosion probes
- Acoustic monitoring

Samples taken from various points within the system, usually at the choke and the separator, provide some indication of the presence of sand, although this will not show if erosion is occurring. This may, however, provide a qualitative indication of sand production and an early warning of the potential for sand-related problems. BSW measurements are routinely taken on every well test so no additional cost or significant planning is required.

Thickness measurements made using an ultrasonic thickness meter are often used as a control for monitoring erosion on pipework. At any given point, a thickness measurement might vary depending on how the operator uses the tool. It is recommended that several checks be made at the same point to establish a reliable thickness measurement. During well test preparation and prior to any production, a representative number of thickness measurements of the pipework are recorded in order to establish a baseline, the number of sampling points varying according to the size of the setup. Fifty to a hundred pipe measurement points is not unusual. The points selected should include those most likely to experience erosion, choke outlets, elbows, reducers, and the like. Each sample point is marked and numbered, so that the same points are measured during successive surveys to establish any erosion trend. There may be occasions that warrant measurement of every elbow. This might be the case if the well test equipment has been in service previously, if its condition is uncertain, or if the probability for sand production is high.

Erosion probes (Figure 5.7) are sacrificial tubes inserted into the flow stream. When erosion exposes the inside of the tube to pressure, this registers on a gauge or an automatic switch to provide a warning that erosion has occurred. In order to be effective, probes should be placed close to those locations where erosion is likely to be greatest.

More sophisticated probes use an electrical resistor (Figure 5.8) as the erosion target. The resistance change as the material erodes is measured and recorded at a computer. This type of measurement provides additional data for erosion rate and sand mass estimation.

Acoustic devices detect the sound generated by the impact of solid particles on the inside pipe walls because they rely on noise detection. The sensors are ideally fitted just after pipe elbows or chokes.

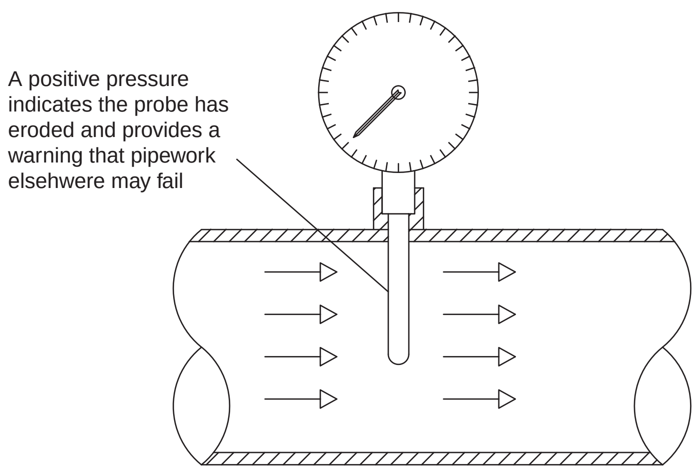


FIGURE 5.7 Erosion probe

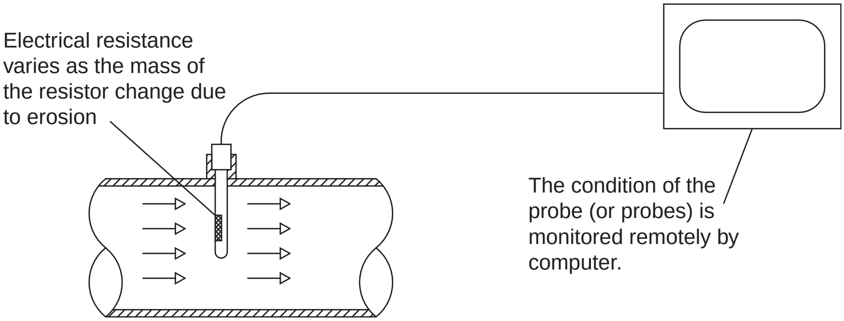


FIGURE 5.8 Electrical resistance erosion monitor

PIPEWORK SIZING

In our earlier discussion, fluid velocity inside production pipework was identified as a factor in erosion. For a given mass flow rate, the velocity of the fluid is greater in smaller pipework because the same mass of fluid must pass the same point in any given time period.

At higher velocities, friction forces between the fluid and the pipe walls are greater and result in increased pressure losses along the entire production system. Higher system pressures are therefore necessary to achieve high flow rates with smaller pipe. Selecting the right pipe in order to achieve the desired production rate for the available operating pressures is an important aspect of well test design.

Since the available pressure from the wellhead is fixed, then varying the size of pipe is the only variable available in order to improve the maximum flow rate. Provided pressure losses due to friction forces are not greater than about half the available wellhead pressure, then the desired flow rate is achievable. In other words, a direct relationship exists between achievable flow rate and pressure loss due to friction. To determine the total pressure loss, calculations are performed for each pipe section, working from the burner head and gas flare tip to the separator and the choke manifold or wellhead. Knowing the available wellhead pressure from nodal analysis, the engineer can determine whether the desired flow rates are achievable. If not, the engineer must select larger diameter pipe. Refinements to the calculation include equivalent pressure drop data for the valves and fittings in the system.

Similar calculations performed for vent and pressure relief lines validate the pipework sizing for these devices. It is essential that pressure relief valves and pipework be able to transport the maximum possible production rate safely. Some common well test pipework sizes and specifications are listed in Table 5.1

NODAL ANALYSIS

Nodal analysis is a modelling tool used by drilling, subsurface, and well test engineers to help achieve an optimum well design in terms of perforations, tubing size, and fluid and underbalance design, as well as to provide some of the key data inputs for the design of surface facilities.

Table 5.1 Common Well Test Pipework

Size	Material	Pipe Schedule	Wall Thickness	Working Pressure	Application
3”	A106 Grade B or A333 Grade 6	XXS	0.674”	10,000psi	High Pressure Fluid
3”	A106 Grade B or A333 Grade 6	80	0.300”	2,500psi	Low Pressure Oil
4”	A106 Grade B or A333 Grade 6	80	0.337”	2,300psi	Low Pressure Gas
6”	A106 Grade B or A333 Grade 6	80	0.432”	2,250psi	Pressure relief lines

All pipe in the above table will be H_2S service in accordance with NACE MR 01 75

Nodal analysis models both the inflow performance of reservoir fluid into the wellbore and the outflow performance of reservoir fluid through the tubing.

The inflow performance relationship (IPR) plots the drop in reservoir pressure with the production rate to produce a characteristic curve for a given set of conditions, that is, reservoir permeability, thickness, pressure drop, wellbore radius, fluid viscosity, and skin (see Figure 5.9).

The outflow, or tubing performance, plots pressure loss in the tubing against increasing flow rate for a given set of conditions, including fluid weight, friction losses, and wellhead pressure. Friction loss in turn is a

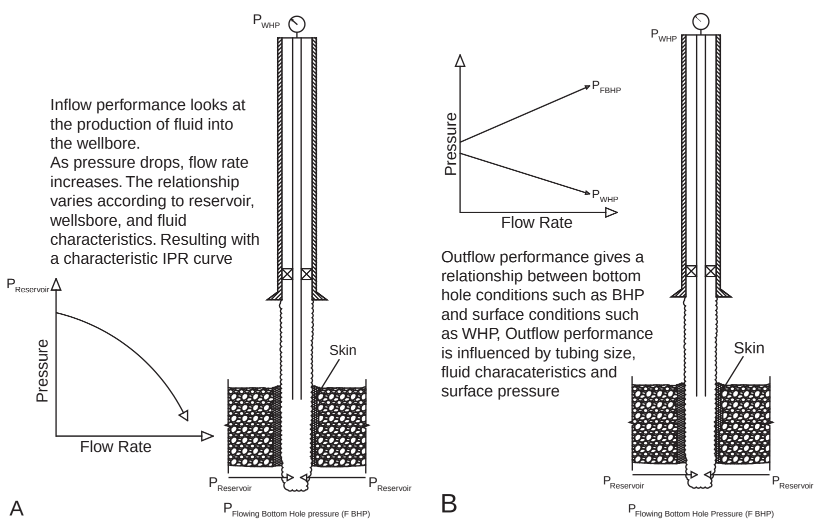


FIGURE 5.9 (a) Inflow performance relationship (b) Outflow performance relationship

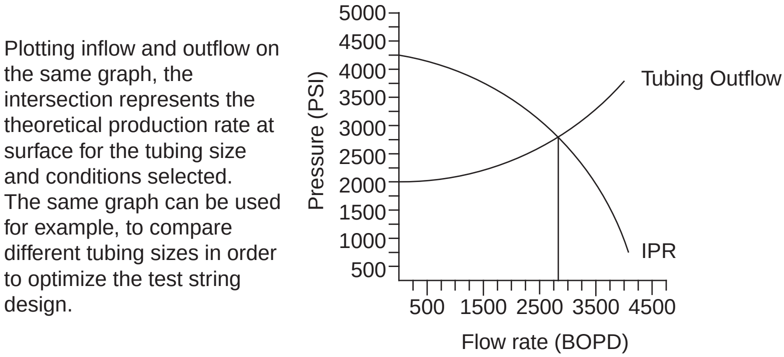


FIGURE 5.10 Inflow versus outflow, tubing sensitivity

function of the tubing size and condition. The plotted results produce a characteristic outflow performance curve.

Plotting these two curves together provides a pressure and corresponding flow rate for a given position along the tubing or at the wellhead. (see Figure 5.10)

The same plot may be produced to compare different tubing sizes and production rates. These comparisons or sensitivities as they are referred to, help the well test planning team to select the optimum tubing. The data from nodal analysis provides pressure and production data that contributes to well design, surface process equipment design, and the well test procedure. This calculation is performed by the subsurface team since it derives from an understanding of the reservoir model and downhole conditions. The well test engineer may provide input on perforation data and available tubing sizes. Since nodal analysis provides such fundamentally important inputs, it must be completed early in planning, during the preparation of the well test Basis for Design.

TUBING STRESS ANALYSIS

Tubing stress analysis calculates the forces and/or movements that act on the tubing, casing, and packer as a result of the weight of tubing, well pressure, surface applied pressure, and temperature effects. Its purpose is to select suitable tubing or to validate the tubing and packer design selected for the well test. Because it influences tubing selection, it must be carried out early in planning so that the tubing size and type can be specified in the Basis for Design.

Nodal analysis helps to determine a suitable tubing size capable of achieving the desired production rate for the well conditions, but the design must also consider the yield strength of the tubing. Under production conditions, tubing is subjected to various loads that can produce significant forces that are sometimes capable of exceeding the inherent strength of the tubing material. When considering yield strength, as with other equipment components, a safety factor is

included. Typically, loads should not exceed 80 percent of yield strength in the case of new tubing. A larger factor of safety is required for old or used tubing and will vary according to material, age, and general condition.

In order to determine the forces acting on the tubing, the well test engineer must consider the operating conditions during the test when the various forces will be at their greatest. Tubing stress analysis calculations are performed using computer programs available to most resource companies and tubing and packer contractors. It is the well test engineer's task to ensure that the inputs for the analysis accurately reflect actual well test conditions. These inputs to the tubing stress analysis are the load cases that define the most extreme range of conditions which the tubing and packer may experience during the test. The well test engineer will discuss these load cases with the packer and downhole tools contractor to ensure they are correct. The initial conditions are those that exist in the well at the time the packer is set, that is, the hydrostatic weight of fluids in the annulus and tubing and surface applied pressure, if any. Maximum drawdown is the drop in pressure downhole associated with production of fluid at surface. The fluid hydrostatic inside the tubing will be at its lowest, while at the same time the pressure in the annulus will be the combined pressure of the hydrostatic annulus fluid weight and the pressure applied on top of this to maintain the tester valve in the open position. During shut-in, the tubing experiences maximum shut-in tubing head pressure, and the annulus is hydrostatic fluid weight only. Contingency kill considers the case where the tubing is full of gas and the annulus has maximum surface pressure applied to operate the secondary circulating valve. Table 5.1 lists a typical set of conditions considered for a well test.

The results produced by the calculation list the various ways in which the forces act on the tubing. Resource companies allocate design safety factors for each so that the tubing and packer do not experience loads outside of their design specifications. A typical set of design safety factors are listed in

Table 5.2 Tubing Stress Analysis Load Cases

Operation	Tubing Fluid	Tubing Pressure	Annulus Fluid	Annulus Pressure
Initial Condition	Kill fluid	None	Kill fluid	None
Maximum Drawdown	Hot-Evacuated	None	Kill fluid	Tester valve opening pressure
Shut in	Gas	SITHP Gas	Kill fluid	Tester valve opening pressure
Contingency Kill	Gas	SITHP Gas	Kill fluid	Rupture disc pressure

Table 5.3 Tubing Stress Analysis Design Safety Factors

Collapse	Burst	Tension	Compression	Triaxial
1.1	1.25	1.6	1.2	1.25

Table 5.2, it should be noted that these values vary from one resource company to the next.

For every tubing stress analysis, the results must be compared against the resource company design safety factors. If any condition exceeds the designated safe limit, then the well test engineer must evaluate the suitability of the tubing and packer or, alternatively, consider procedural controls that avoid exposing the tubing to the conditions that give rise to the unsafe load. Such measures can only be made with an appropriate risk assessment and with well-defined procedural controls. Figure 5.11 illustrates a set of load cases more graphically.

If the packer and tubing are fixed together, as in the case of a tubing conveyed packer, the forces acting on the tubing also act on the packer. In addition to the loads transmitted through the tubing, the packer also experienced forces directly as a result of pressure acting from above and below. All packer manufacturers provide packer design envelopes (Figure 5.12) that define the limits for the load conditions within which the packer will operate reliably.

Figure 5.12 illustrates a typical packer design envelope. The results of the tubing stress analysis are assessed to ensure that the load conditions do not exceed design specifications.

HAZARD AND OPERABILITY

When the components of well test equipment are assembled together, their varying specifications make the task of assessing the overall suitability of the system a complex one. To take an example, a high-pressure manifold, rated to 10,000 psi working pressure, will readily contain a 5,000 psi well head pressure, but downstream of this manifold, other devices such as separators, pipework, tanks, pumps, and burner heads cannot contain this pressure. Controls are required in order to ensure that this low-pressure equipment is not exposed to high pressure by accident and that equipment and personnel are protected from this and other potential hazards to the system.

A Hazard and Operability study (HAZOP for short) is a procedure that follows a standard in order to assess the suitability of a particular process system. The analysis is performed using the operating envelope for the test to define the extremes of conditions to which the equipment is exposed.

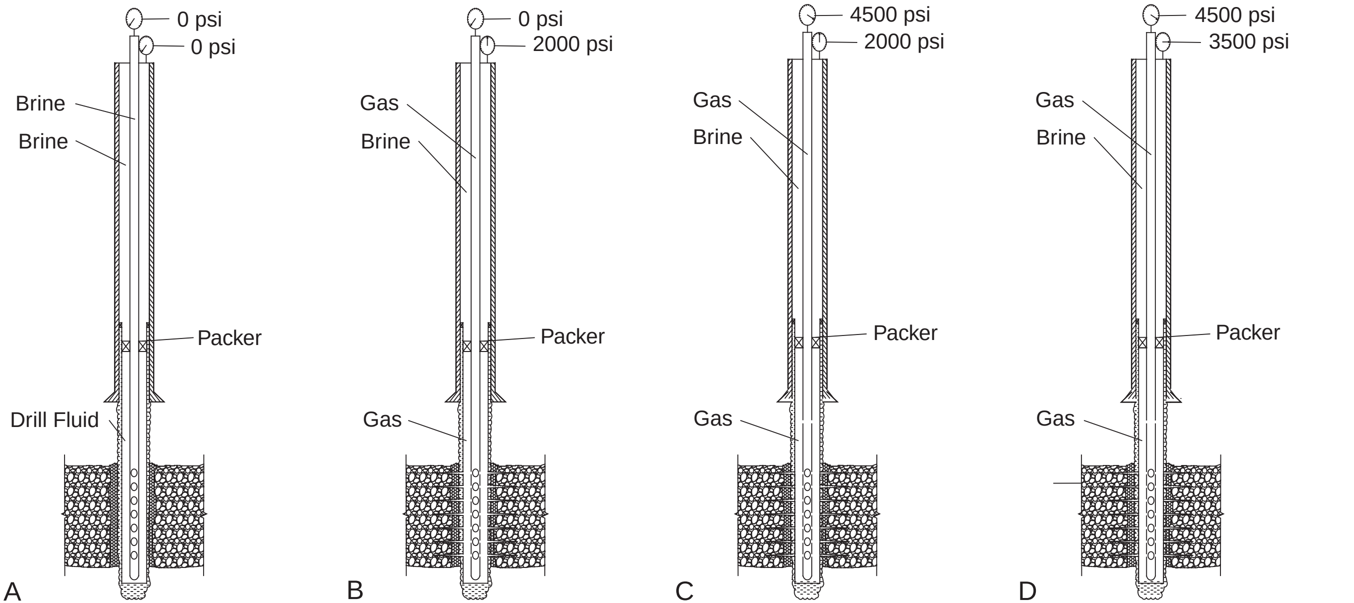


FIGURE 5.11 Tubing stress analysis load cases

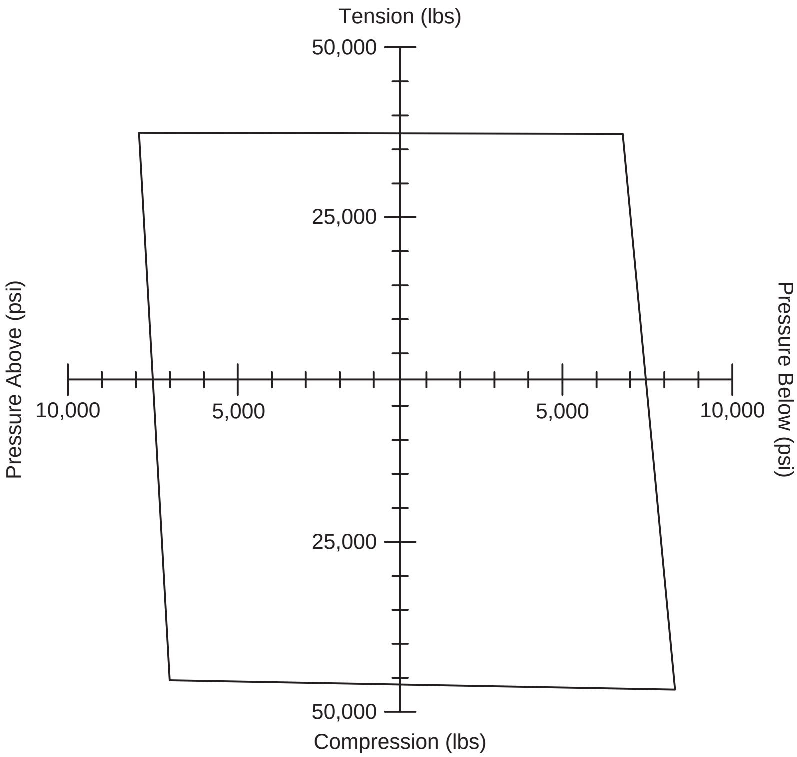


FIGURE 5.12 Example packer operating envelope

This procedure identifies the controls required for each of the conditions that can present a hazard to the process. The methodology within the various standards follows a similar set of steps.

1. Assemble a representative team of experienced personnel with a relevant spread of technical knowledge.
2. Divide the well test process equipment into logical nodes, that is, segments of the process that share the same specifications and are protected by the same safety devices.
3. Define the operating envelope and specifications for each node.
4. Apply a set of guidewords (variable conditions) to each node and identify production condition deviations produced by each variable, that is, High Pressure, Low Pressure, Gas Blow By, Liquid Blow by, Excess Temperature, Low Temperature.
5. Agree on the controls required to protect the system from the deviation in conditions. The controls might include a combination of one or more of the following: indicator devices, alarms, automatic shutdown devices, pressure-relieving devices, check valves, flow restrictors, fusible plugs, spark arrestors, and control valves.

6. The procedure provides a method for capturing the information from the HAZOP into a standard format called a safety analysis table (SAT). Each device is also marked on a piping and instrumentation diagram (P & ID), which becomes an important reference document for the scope of supply and the installation and commissioning procedure for the well test equipment at the well site.

The well test engineer plays a central role in coordinating the personnel and resources required for this process. Often, the HAZOP is facilitated by a third-party contractor specializing in this type of analysis process

RIG INTERFACE ENGINEERING

At a land-based well site, well test equipment other than support utilities such as water and power is supplied entirely by contractors. Offshore, most drilling facilities supply some of the equipment necessary for well testing, without which the preparation required for every well test would entail considerable engineering. This section describes the well test equipment that might be expected as part of the drilling facility scope of supply, together with a description of the utilities and other well test interfaces.

Pipework

Pipework utilized for surface flowlines and standpipes is generally separated into two material groupings, 4130 and 4140. These are alloys hot worked or extruded and suited to high-pressure applications, such as for derrick standpipes and high-pressure flowlines. In general, 4130 material is preferred; 4140 is a harder material and is not suited for sour service. A106 and A333 are material references for pipework applied to low-pressure applications and recommended by NACE. These materials are appropriate for working pressures of 1440 psi. A333 is suited for work at low and high temperatures, while A106 is not suited for temperatures below 0 Celsius.

In general, larger diameter pipe is preferred for gas pipework because it permits higher production rates, reduced back pressure, reduced noise, and reduced risk of flow erosion due to reduced fluid velocity. The pipework guidelines listed below provide some specifics in relation to well test pipework.

To avoid confusion, it should be noted that materials utilized in surface pipework differ from those used for tubing. Materials specified for tubing are identified by yield strength. For example, L80 or J55 refers to tubing joints with yield strengths of 80,000 psi and 55,000 psi, respectively. This type of tubing is not suited for surface pipework applications, it is cold rolled, welded, and treated, and it does not lend itself to welding to attach surface pipe fittings. These tubing sections are manufactured with threaded ends that permit connecting the tubing lengths as they are run into the well.

Pipework Guidelines

1. Where practicable, route pipework away from accommodation areas, lifeboats, escape routes, and other safety-critical areas.
2. Route pipework clear of heat sources or areas where pipework may be exposed to impact from crane lifts.
3. Use the most direct route between the well test area and the flare booms, allowing for the considerations above in order to minimize pressure losses.
4. All pipework must be securely anchored using adequate clamps and brackets to restrict vibration and control reaction forces in the event of pipe failure.
5. Minimize elbows where possible.
6. Avoid low points where water and other fluids may sit and accumulate.
7. Keep pipe flanges away from nonhazardous-rated electrical equipment
8. Use pipework welding procedures as per ASME B31.3
9. Make calculations for wall thickness, pressure, and temperature rating as per ASME B31.3.
10. Make calculations for working pressure based on pipe wall thickness, and not on the hammer union end fitting often rated to higher working pressures than the pipe material.
11. Make sure hydrocarbon-bearing pipework is sour service and complies with NACE MR0175, pipework material A106 Grade B, or A333 Grade 6 or equivalent. A333 is preferred.
12. Use recognized hammer union fitting manufacturers, FMC and ANSON.
13. A hammer union connector thread half comprising the elastomer lip seal shall be considered the "female" half and is utilized for the inlet of a section (see Figure 15.13).
14. A hammer union connector that incorporates the "nut" and the hammer lugs is the "male" half and is utilized for the outlet of a section.
15. 2 in. 602 Female can potentially connect to a 2 in. 1502 Male; for this reason 2 in. 602 unions are not recommended and on many facilities are prohibited.
16. 2 in. 1002 has the same thread as 2 in. 602 and is prohibited in well testing.
17. Articulated or swivel pipework should not be used on hydrocarbon lines.
18. Threaded fittings should not be used; pipework sections and end fittings should be welded.
19. Pipework supplied with full material traceability, welders certificates, welders procedures, pipework calculations, and as built drawings. Substantial welded steel bracelets attached to the pipework should be used for specification and traceability information.

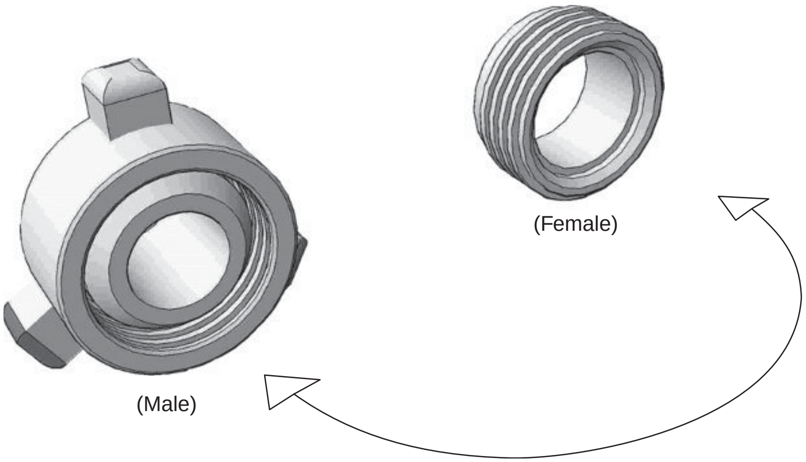


FIGURE 5.13 Weco hammer union

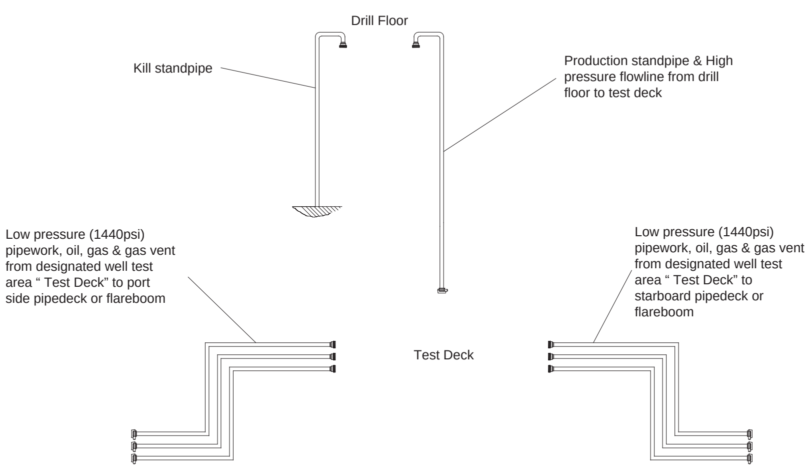


FIGURE 5.14 Typical rig supplied well test pipework

FLANGES, STUDS, AND FITTINGS

Bolted flanges are used in preference to hammer unions when metal-only seals are permitted or more desirable. Near the flowhead, high temperatures and high levels of CO_2 and H_2S dictate the use of metal-only seals. Elsewhere, bolted flanges are used where connections are not routinely broken between well tests. These are the intermediate connections joining various components of a piece of well test equipment, the choke manifold, steam exchanger, separator, diverter manifold, transfer pumps, and burner heads; all have some bolted flanges. Hammer unions are used on inlet and outlet connections to interconnect this equipment. The strength of the bolted flange connection is dependent on the makeup torque of the flange studs because flange studs

are an item frequently changed during service work on well test equipment. They can be replaced using studs and nuts with the incorrect material. Compliant studs are stamped with a material mark at either end, L7 or B7. The flange studs must extend beyond the end of the bolt in order to achieve a full-strength connection. (See Figure 5.15.)

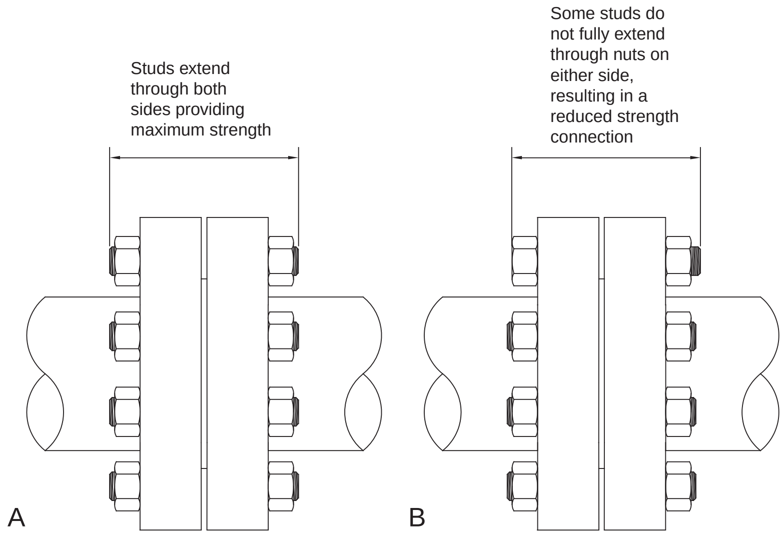


FIGURE 5.15 (a) and (b) bolted flanges

FIGURE 5.16 Photo corroded NPT thread

Table 5.4 Common Threaded Fittings

Thread Size	Working Pressure	Test Pressure
½” NPT	10,000 psi	15,000 psi
¾”-2” NPT	5,000 psi	10,000 psi
2 ½”-6” NPT	3,000 psi	6,000 psi

The industry has seen fatalities and serious injuries arising from the misuse of threaded fittings, in particular with corroded box threads that only provide partial thread engagement. Thread gauges should be used during maintenance and inspections to ensure thread fittings are in good order. The assigned pressure rating for each fitting size and material grade must be respected.

NPT (National Pipe Taper) is a common oilfield thread governed by ANSI/ASME B1.20.1. Common sizes in use include 1/8”, ¼”, ½”, ¾”, 1”, 1 ¼”, 1 ½”, and 2”. The smaller sizes in particular are used for high-pressure applications up to 5,000 and 10,000 psi. High-pressure fittings should be manufactured of stainless steel grade 316 (316SS). NPT threads have a slight taper and should not be confused or interchanged with National Pipe Straight (NPS); in addition, NPT threads require polytetrafluorethylene PTFE (Teflon) tape to achieve a pressure seal. This also acts as an anti seize to facilitate later removal of the fitting.

Well Test Equipment Placement Guidance Notes

The following notes provide guidance on issues relating to deck placement and general interfaces between the well test equipment and a MODU facility.

ESCAPE ROUTES

Plan at least two independent escape routes from the well test area and consider providing a deluge to cover the primary route. Escape routes should be located on opposite sides of the well test area, so that if one escape were blocked, for example due to fire, then personnel located in the test area could access the alternative route located in the opposite direction. These should provide for walkways free from obstructions with adequate width and height clearance, so that personnel can move quickly without having to crouch or duck to avoid pipework or other obstructions.

ACCOMMODATION A60 FIRE WALLS

The well test equipment must be located as remote from the accommodation as possible. The accommodation bulkhead, together with any office units or locations where personnel are likely to be working during a well test and which are close to the well test area, must be protected by A60 fire walls.

FIRE ALARMS

Due to the noise levels frequently encountered during well test activity, it is recommended that the well test area be supplied with both visual and audible emergency alarms and activation switches located near the escape routes.

DELUGE

The well test area should be supplied with suitable fire-fighting equipment. This may include a deluge surrounding the well test area capable of blanketing the well test equipment in the event of a fire and/or substantial fire monitors located so as to provide operators with a clear throw to the well test area. Monitors will not necessarily be located in the well test area since any fire associated with the well test equipment may render them inaccessible to the fire team.

COMMUNICATIONS

Locate at least one handset along each escape route linked to the facility internal communications system. It is recommended that each handset be housed inside a sound-absorbing shield to facilitate better communications during testing.

ELECTRICAL SUPPLY

Although air-powered equipment is recommended whenever possible, use of electrical power for some equipment is unavoidable. Typical electrical power requirements for a well test package are listed in Table 5.4.

Like all electrical points on the deck of a MODU, the connections must comply with international standards for the use of electrical equipment in potentially hazardous environments.

UTILITIES

Instrument air, drill water, and seawater are utilized for many items of test equipment. Crowfoot connections are the most common connection for use

Table 5.5 Well Test Electrical Equipment

Item	Location	Supply Voltage	Supply Current
Office Container	Well test area	380–440 VAC 3 Phase	25A*
Transfer Pump	Well test area	380–440 VAC 3 Phase	55A*
Steam Boiler	At least 20 m remote from well test area	380–440 VAC 3 Phase	25A*
Ignition System	Each flare boom	110–240 VAC	10A*
Lighting	Various	110–240 VAC	10A*

*Indicative.

with air and water supply. Fatalities and injuries have occurred through the misuse of these connections. Flexible hose connected to these supply points must be in good condition and secured to the end fitting with approved connector clamps. R-clips and whip checks must be used to secure crow's foot connections.

CEMENT UNIT

The cement unit is a contractor-supplied and -operated pump unit capable not only of high volumes and pressures, but also of precision work such as pressure testing and cementing. In preparation for well test operations, the cement unit is used to pressure-test equipment and to pump underbalance and kill fluids. Open top displacement tanks attached to the cement unit are normally used to store fluids in preparation for pumping operations. Because regulations prohibit filling these tanks with diesel, the cement unit must take a direct diesel supply from an alternative source, offshore the MODU motor room. This feature is not always available on every MODU and may require installation work in preparation for the test. The addition of such a line may also require a revision to the fire and explosion analysis in the MODU Vessel Safety Case.

The cement unit is also utilized to pressure-test the well test equipment and to calibrate well test production meters on the separator. The standard pipe configuration for a typical cement unit follows a standpipe from the cement unit to the drill floor, then down to the main deck via the well test flow line. Ideally, well test pressure testing occurs off critical path, but for safety reasons, pressure testing using the drill floor pipework is often prohibited while other operations take place. This imposes restrictions that may result in this operation occurring on critical path. The cost of installing a dedicated high-pressure test line between the cement unit and the well test area directly, bypassing the drill floor, might be justified for this reason.

LIGHTING

Well test activity is a 24-hour operation; thus, adequate lighting is essential to ensure the safe continuity of operations. Lighting must cover the entire well test area to enable personnel to operate equipment and to see instrumentation clearly, as well as to clearly illuminate the escape routes. All lighting must be certified for operation in hazardous areas. Hand held torches must also be intrinsically safe for use in hazardous environments.

FLARE BOOMS

Offshore, hydrocarbons produced during a well test must be disposed of in a manner that is safe for handling and minimizes the risk for environmental contamination. On a production facility, hydrocarbon products might be taken into the production line. However, this option is not available on an

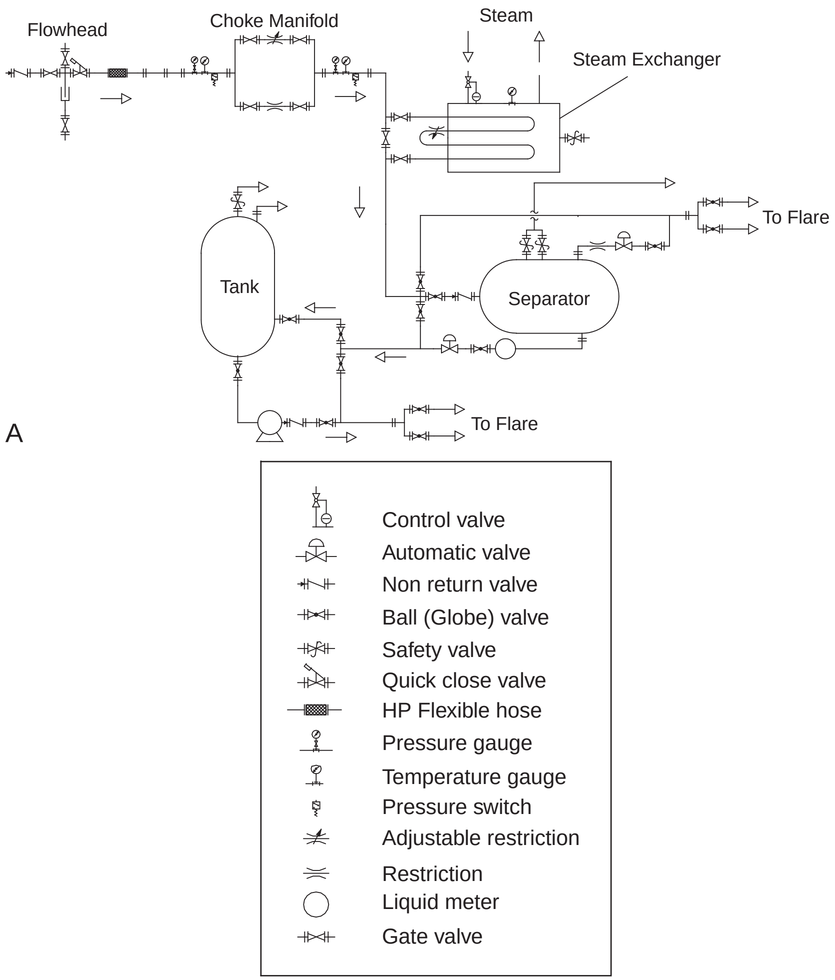


FIGURE 5.17 Cement unit P & ID

exploration facility. A practical and widely utilized method for disposal is flaring. This activity generates significant heat radiation that must be controlled. For this reason the flaring takes place at the end of a flare boom, which extends from the side of the facility to reduce the effects of head radiation. There are practical limits to the length of the flare boom imposed by the weight and strength of the boom and the support structure. In practice, flare booms might vary in length between 20 m and 30 m. Because many drilling facilities are moored and therefore cannot orientate if the wind direction changes, most facilities carry two flare booms, one on either side to allow continuity of operations regardless of wind direction.

Many facilities provide their own flare booms as part of their scope of supply for well test equipment. Contractor-supplied flare booms can be installed

at a facility, but this type of installation requires substantial planning and engineering work.

The following list provides some guidelines relating to flare boom installation on an exploration facility.

1. Position flare booms away from the accommodation structure.
2. Ensure that facility cranes on both sides have adequate reach for installation and removal of booms and burner heads.
3. Assess the deck structure providing support to the booms and any king-post supports in order to establish that it has adequate strength for the loads.
4. Where practicable, minimize the distance between the well test area and the booms.
5. Consider the location of other equipment and areas that may be affected by heat radiation, electronic navigation equipment, flammable paint stores, fuel tanks, pressure vessels, lifeboats, and lifesaving equipment and general work areas.

RIG COOLING

Heat radiation from flaring will act on every surface in line of sight from the source, including the facility structure, fuel tanks, columns, support legs, accommodation, paint stores, cranes, tanks, containers, lifeboats, and electrical equipment. By raising the temperature of a surface, the object in question may experience damage due to overheating. Its contents may catch fire, or a pressure vessel may experience an overpressure. In order to help control these hazards, most facilities provide cooling systems designed to create a water shield between the flare source and the side of the facility. The water shield absorbs much of the radiated heat, reducing the intensity to a safe level. The effectiveness of the water shield depends on the amount of heat radiation, the pumps supplying the water to the cooling system and the general condition of the pipework and diffusion nozzles. The water shield in itself may not be the only control; heat shields provide an effective barrier to protect personnel and equipment. Heat shields are blankets manufactured from heat-resistant material similar to that utilized in fire suits and suspended along the side of the facility or blanketed over equipment for protection. Unlike water cooling, heat shields are passive; that is, they are not dependent on the continuous operation of pumps to be effective. Heat shields are not normally supplied by the facility.

COMPENSATOR SYSTEM

The compensator system is designed to reduce the impact forces arising out of the relative motion of a floating facility and the well. During installation and retrieval of the workstring, the potential for a high impact resulting in equipment damage could occur between upsets in the workstring such as at the

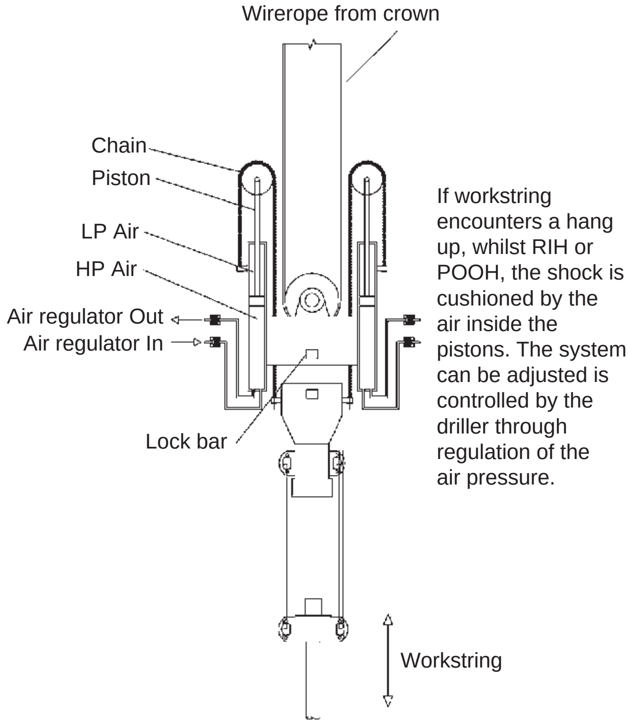


FIGURE 5.18 Compensator system

packer and subsea test tree against upsets in the well, such as liner hangers, the wellhead and the BOP. The compensator introduces an air cushion acting on a piston, as the weight on the workstring drops when it contacts a fixed point inside the well, the force is transmitted to the piston which compresses the air and so cushions the effect of the impact. (See Figure 5.18)

DRILLING RIG P AND ID

The schematic in Figure 5.19 represents a typical drilling rig tank and pipe configuration. Drilling fluids are stored in the pits. Mud pumps transfer this fluid to the workstring or the annulus as required. The returned fluid travels through the gas separator or directly to the shakers for filtering and then back to the pits or overboard. The trip tank provides the driller with a reservoir to store fluid in order to rapidly top up the well volume or to take returns in the event of gains and generally to provide a means of monitoring fluid volumes in the well.

FACILITY DESIGN AND ENGINEERING REPORT

This report describes the design and engineering input to the surface well test facility. The name and content of this report might vary from one contractor to

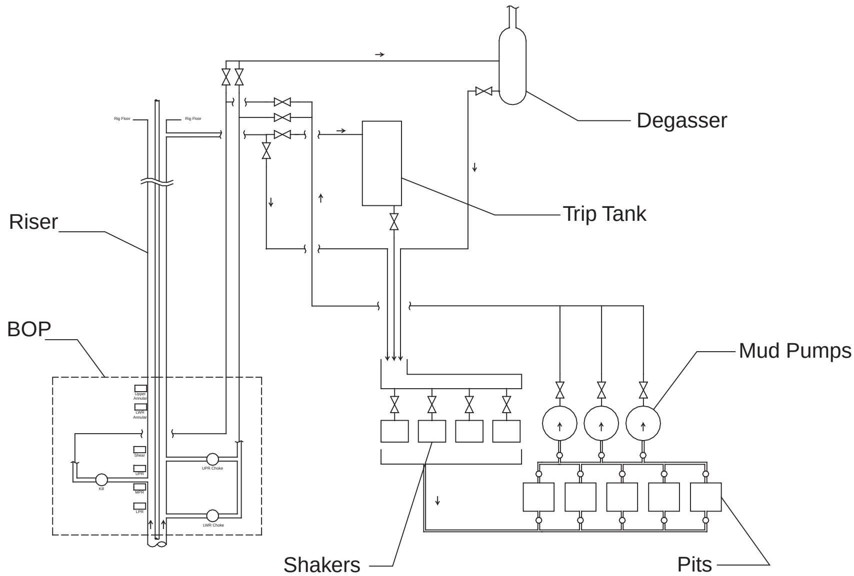


FIGURE 5.19 Drilling rig P & ID

the next, but the well test engineer reviews this report to ensure that the most important engineering features are described accurately and in sufficient detail so as to demonstrate that the facility is fit for its stated purpose.

Typical elements of a well test design report

- Reference standards
- Operating envelope
- Process equipment
- Equipment placement
- Set of drawings (layout, hazardous areas, process and instrumentation)
- Back pressure and pipe-sizing calculations
- Safety system engineering (philosophy)

Reference Standards

A reference standard provides a control to ensure that a process, together with the product that is the output of a process, is free from faults and capable of performing its intended purpose — in other words is fit for purpose. One objective of a well test design report is to demonstrate that the engineering input to the design of a surface well test facility is fit for purpose. In order to achieve this objective, the engineering input to the design adheres to various standards, including welding, vessel design codes, pipework, electrical standards, and other engineering standards that apply to valves, seals, and other components of test equipment. Listing the reference standards in the report provides a means of auditing the design.

The well test engineer reviews this report when planning has advanced far enough for the well test contractor to complete the detailed design work. This is often close to the mobilization of equipment to the field. The well test engineer assesses the report for completeness and accuracy, including a check to ensure that appropriate industry standards have been applied to the design. Under some regulatory environments, this report is subject to review by an independent well test engineer or organization, sometimes called a peer review or validation. Often, an external observer not involved with previous planning can identify issues, omissions, and mistakes overlooked by those directly connected with planning.

Operating Envelope

The operating envelope is the set of production conditions for which the process equipment has been designed. Those conditions are pressure, temperature, fluid type, production duration, and production rate. It is important that these conditions are listed in the design report, for a number of reasons. First, to ensure that the correct conditions have been used for the design work, the contractor obtains this list of conditions from the Basis for Design document prepared by the well test engineer. Often, production conditions are revised during planning based on additional or refined data. The well test engineer is responsible for ensuring that the contractors performing the design work use the current available data. The Basis for Design document is a controlled document for this reason. Secondly the reason for ensuring that the operating envelope conditions are current is for reference. Personnel including contractors and supervisors at the well site must be aware of the operating limits for the system so that they can take the necessary steps to ensure that none of those conditions are exceeded. Finally, the information in this document provides a reference for regulators, managers, and third-party design verification engineers.

Process Equipment

The design report lists the equipment that makes up the process facility. Each item has its own purpose and set of specifications. The well test engineer reviews this list referencing the contract and planning documentation to ensure it is comprehensive and accurate. The specifications must be adequate to meet the conditions defined by the operating envelope and the standards applicable to each component consistent with the agreed-upon well test design standards. That is, the design standards must meet industry, regulatory, company, and contract specifications.

Equipment Placement

Well test equipment brings with it hazards that are not normally encountered during drilling operations. The storage and handling of hydrocarbons on deck requires careful management. For this reason, most offshore rigs assign a

Table 5.6 Process Equipment List and Specifications

Item	MAWP MPa (psig)	$Temp_{min}$ Celsius	$Temp_{max}$ Celsius	Design	Nominal Size
Flowhead	69 (10,000)	– 20	120	API 6A	76 mm (3")
HP Flexible Hose	69 (10,000)	– 20	100	API 16C	76 mm (3")
Shutdown Valve	69 (10,000)	– 20	120	API 6A	76 mm (3")
Choke Manifold	69 (10,000)	– 20	120	API 6A	76 mm (3")
Steam Exchanger	69 (10,000)	– 20	120	ASME API 12K	1281 kwh (4.3 MMBTU)
Boiler	1.17 (170)	0	100	ASME 8 Div1 ANSI B31.3	1281 kwh (4.3 MMBTU)
Separator	9.7 (1,440)	– 20	120	ASME 8 Div1 ANSI B31.3 ASME B16.5	1.7 MMm3 (60MMSCF)/ Day
Oil Manifold	9.7 (1,440)	– 20	100	ANSI B31.3 ASME B16.5	51 mm (2")
Surge Tank	0.34 (50)	– 20	88	ASME 8 Div1 ANSI B31.3 ASME B16.5	12.7 m3 (80bbl)
Transfer Pump	2.0 (300)	– 20	100	ANSI B31.3 API 610 API 682	795 m3 d (5000BPD)
HP Pipework	69 (10,000)	– 20	120	ANSI B31.3	76 mm (3")
LP Pipework	9.7 (1,400)	– 32	121	ANSI B31.3	76 mm (3")
LP Pipework	9.7 (1,400)	– 32	121	ANSI B31.3	102 mm (4")
Burner Heads	6.9 (1,000)	– 20	N/A	ANSI B31.3	477–1908 m3 d (3000–12000BPD)

specific area for the location of well test equipment. The designated area locates well test equipment, as far as practicable, from the accommodation and from other areas where well test activity might clash with essential facility equipment or services. The Vessel Safety Case assesses hazards associated with the placement of well test equipment in this area. Only in exceptional circumstances will this location change to meet the needs of individual operations. Completions or coiled tubing placement might necessitate moving well test equipment to a new area. Assigning a new area for well test use constitutes a significant change and requires formal risk assessment. Factors to consider with equipment placement include normal rig operations, fire equipment location and suitability, escape routes, deck loads, crane capacities, hazardous equipment, other work areas and work activity, and the safe and practical operation of the well test facility itself. These issues are considered during the rig site visit and in consultation with rig management during

planning. The final agreed placement is captured with a drawing showing the location of each of the main well test equipment components. This drawing also identifies areas required for laydown, preparation of equipment, subassemblies, TCP guns, and transport containers and baskets. A wet weight, that is, the weight of each component when filled with seawater and dimensions are needed to ensure that deck loads are not exceeded.

A layout drawing is a plan view showing the well test equipment in position on the deck of a facility or well-site location.

A hazardous area drawing marks on top of a layout drawing those areas considered hazardous during a well test operation, the hazard being the presence of flammable hydrocarbons. These areas can be further classified if the level of hazard changes for different parts of the process. Areas where hydrocarbons are continuously present in the atmosphere are more hazardous than areas where hydrocarbons are present for only short periods or not at all. Such classifications identify each area as a zone 0, 1, or 2 accordingly.

A well test hazardous areas drawing (Figure 15.21) incorporates existing hazardous areas specific to the facility with those introduced by the well test. A hatch overlay on the drawing highlights the hazardous areas and is sometimes color coded according to the zone classification.

What is this drawing used for? The presence of hydrocarbons in the atmosphere is a hazard that has the potential to lead to fire and explosion should the right conditions occur, that is, an ignition source such as a spark from an electrical circuit, welding equipment, or motor. The drawing defines areas within which all sources of ignition or possible ignition must be removed. Electrical equipment not certified for hazardous areas operations must be isolated, including power points, light switches, exhaust/intake fans, motors, welding, and cutting equipment. Hot work and other unnecessary activities are shut down during well test operations. In particular, crane activity over live well test equipment is prohibited.

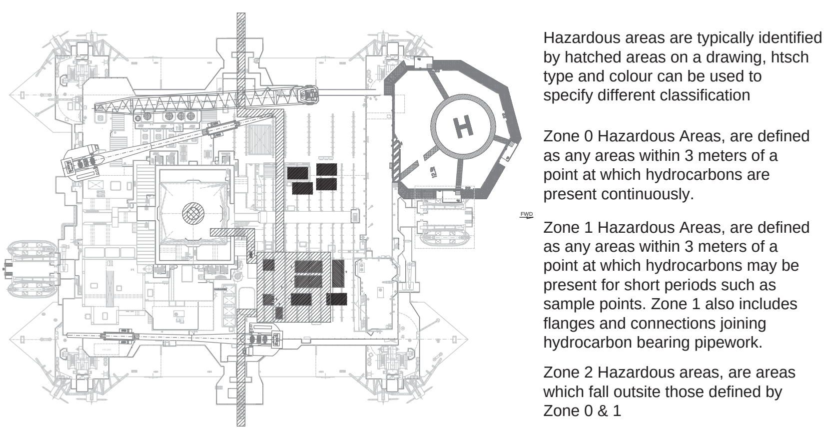


FIGURE 5.20 Well test hazardous areas drawing

This drawing is referenced during planning in order to optimize the routing and layout of equipment, and it is also utilized by rig management to review the equipment setup to ensure that all ignition sources are safely isolated.

A piping and instrumentation diagram (P & ID) is a drawing or, in some instances, a set of drawings, which represents the entire surface well test process system detailing equipment, piping, and instrumentation (Figure 5.22). It serves several purposes. As a scope of supply document, it indicates all of the equipment required in the surface equipment process, including specifications and details of type size and location of crossovers, pipework, instrumentation, and safety devices. It also indicates the assembly order for all equipment and so provides a reference to well site management as a check for auditing the equipment setup. The P & ID also communicates details for the proposed setup to other parties, including the regulator, validation engineer, other planning team members, and resource company management.

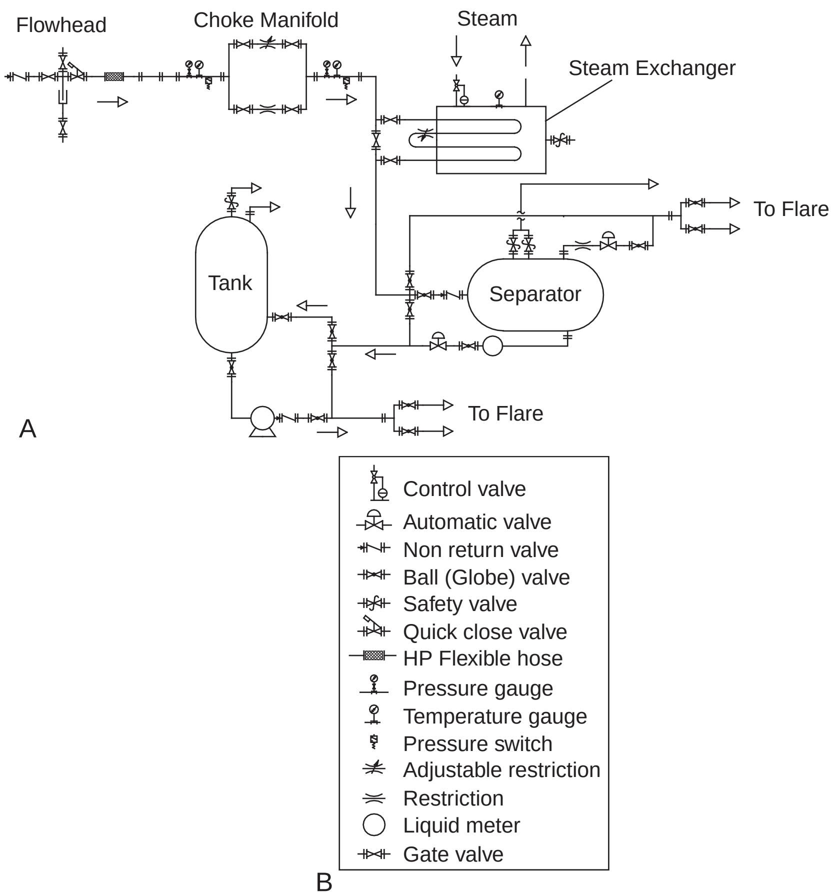


FIGURE 5.21 (a) Basic well test P & ID (b) P & ID symbol key

Deck Load

An important rig interface is the weight of the test equipment and the capacity of the deck to support it. The deck load capacity is available from the owner and is specified in the facility description section of the Vessel Safety Case. This information is required by the class society that provides the MODU certification. Not all deck areas will have the same capacity. Some areas, such as BOP housings, accommodation units, wing decks, lifeboat decks, and a number of other areas around the rig, are designed for very specific applications and often have little or no load-bearing capacity. Pipe decks, riser decks, and dedicated laydown areas typically have the greatest load-bearing capacity. Load capacity is determined by the type of deck plating and deck beams fixed to the plating to distribute loads and the support provided below the plating that can contribute the greatest part of the strength. Load-bearing capacity has two components: the overall load capacity of the area in question and the unit area load capacity. Metric units are given as kgs/m2, while imperial units are given as psf (pounds per square foot). A drawing of the deck provides one of the best means of presenting this information with hatched shading to identify areas with distinct load capacities (Figure 5.22).

Unit load capacity is particularly important for heavy loads that have a small footprint on the deck. When considering well test equipment, a table detailing the wet weight and footprint dimensions for each item is used to calculate and present the load contribution of the well test equipment. Wet weights are the weights of the various items of equipment when full of fluid, usually calculated based on seawater. Concentrated deck loads for items such as vertical surge tanks are often a concern and frequently exceed the deck load capacity, particularly on older facilities. In order to overcome this problem, the surge tank can be mounted on spreader beams to distribute the load or located on deck directly over a major supporting member. Some other controls involve restrictions as to the maximum fluid levels permitted in the tank.

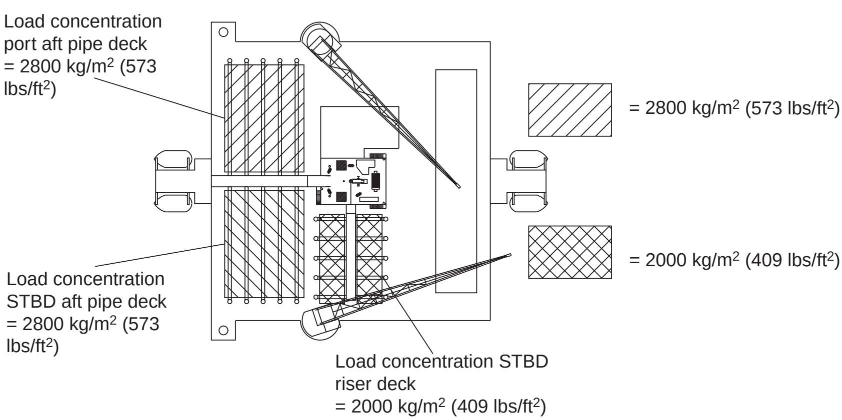


FIGURE 5.22 Deck load drawing

Well Test Equipment Deck Loads						
Item	Description	Wet Weight Kg	Length m	Width m	Load kg/m^2	Load lbs/ft^2
1.0	Choke Manifold	2000	2.5	2.5	320	66
2.0	Steam Exchanger	23000	5.8	2.5	1586	325
3.0	Separator	26000	6.0	2.5	1548	317
4.0	Surge Tank	19000	7.0	2.4	1131	232
5.0	Gauge Tank	22000	5.5	2.6	1399	287
6.0	Steam Generator	10000	6.0	2.5	667	137
7.0	Compressor	5000	4.5	2.5	444	91
8.0	Office Container	8000	4.5	2.5	711	146
9.0	Workshop Container	10000	4.5	2.5	889	182

FIGURE 5.23 Well test equipment loads

Back Pressure and Pipe Sizing Calculations

The report must provide details of the pipe sizing and back pressure calculations (see Figure 5.24) to demonstrate the suitability of the pipework selected for the process equipment. The calculations must also include the line sizing for pressure safety valves. It is essential that pressure relief pipework and valves are capable of transporting fluids at the maximum possible production rates in order to protect equipment and personnel. Should this pipework restrict the flow at high rates, the inflow to the system will potentially be greater than the outflow and exceed the pressure-containing capacity of the equipment.

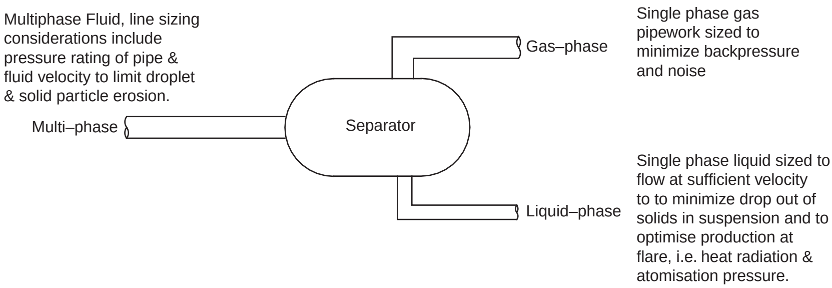


FIGURE 5.24 Pipe sizing

Safety System Engineering

This section describes the safety philosophy behind the engineering design. A typical approach incorporates three levels of safety protection, although the first level is not an engineering control per se because it requires manual activation of the emergency shutdown system (ESD). Well test operations, unlike production operations, are continuously attended, such that manual intervention is available at all times. Important features of this level of protection are the location of the ESD manual switches, which must be selected so that they are readily accessible to personnel within the well test area and the instrumentation providing an indication of the status of the process. Monitoring of the process takes place locally, with gauges fitted to the process

equipment and remotely with a computer acquiring and displaying the data to a technician at a remote data-gathering location.

The second level of protection is automatic shutdown. Automatic switches located throughout the process equipment sense the conditions within the process and activate the emergency shutdown system if the conditions sensed by the switch exceed a preset value. The settings and locations for each switch are determined during the HAZOP and are indicated on the P & ID.

The third level of protection is automatic pressure relief to a safe area. Pressure safety valves (PSVs) fitted to vessels and pipework are preset to open at or below the safe working pressure of the device to which they are attached. Calculations are performed to verify that the design of the PSV is such that the maximum throughput of fluid from the well can be handled safely by the device. Unlike the first two levels of protection which involve a delay between an unsafe condition occurring and the shutdown system activating, the PSVs activate immediately to vent excess pressure and protect personnel.

DESIGN REVIEW

The engineering controls incorporated into the well test design are the subject of successive reviews (Figure 5.25), initially by the contractor preparing the technical response for the resource company, followed by the well test engineer and the resource company planning team, and finally by an independent, regulator-approved, review engineer. This third reviewer is mandatory in only some parts of the world. In either event, the review of the engineering input to the design requires a design report that details the preparations made by the contractor, the standards list providing an audit reference. The review must also include an assessment of equipment maintenance and certification records to show that the equipment has been prepared in accordance with the information detailed in the design report.

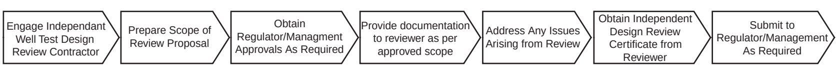


FIGURE 5.25 Design review flowchart

Chapter | six

Planning for Safety

CHAPTER CONTENTS

Risk is a term applied to any hazard that may have consequences threatening not only people but also the environment, business reputation, and cost. When we talk about safety, we simply mean that specific category of risk that has the potential to harm people.

Performing any task has some health or injury risk potential. The only way to reduce that risk to zero is to avoid the task entirely. This is hardly a practical solution for every task, but it may be reasonable to proceed with a hazardous task if the risk can be reduced. Risk management is the process of identifying hazards, assessing risk levels and introducing controls to reduce risk to acceptable levels.

Consider the challenges presented by a well test. This is a complex operation comprising multiple tasks performed by a mixed group of contractors and employees. Many of the tasks are inherently hazardous and relate to pressure, flammable liquids and gases, explosives, toxic chemicals, working at heights, confined spaces, noise, heat stress, lifting, trips and falls, and manual

handling. The complexity of the operation demands a structured approach to the management of safety. The aim of this chapter is to describe a management of safety process specific to well test operations.

The essentials for this management process are as follows:

1. A process for identifying the hazards associated with each task
2. A process for identifying controls for each hazard
3. A process that ensures those controls are implemented

As with any hazardous operation, as soon as it is considered routine, those involved with planning that operation or with its execution are in danger of becoming complacent, with the result that risks associated with any of the operational hazards increase significantly. Formalizing the approach to safety helps to maintain focus on the operation as a hazardous one. Importantly, the resource company, and in particular, the well test engineer must take the lead in promoting a safe behavior through which every hazardous operation, no matter how often it is repeated, is not treated as routine. Well tests may be frequent in the industry but never routine.

ONSHORE VERSUS OFFSHORE

Well testing is hazardous regardless of whether the operation takes place onshore or offshore; the inherent hazards associated with handling hydrocarbons under pressure are the same. In this chapter, many of the processes described were developed specifically for offshore oil and gas exploration. However, much of this chapter is equally applicable for onshore operations. In particular, the engineering, process design and risk assessment elements can readily be applied to onshore well test operations.

WHY IS A WELL TEST SPECIAL?

The safety systems built into a drilling facility are designed to maintain control of drilling hazards through the use of BOPs, mud systems, casing design, and drilling technique. In the event of an uncontrolled release of pressure, the BOP and diverter are designed to contain the release until the mud system is weighted up to bring the well under control again with overbalance. A well test is unique, replacing the overbalance with an underbalance. Well fluids are deliberately brought to surface with specialized equipment and procedures, with the result that controls normally available for drilling are not available for testing. Because a well test introduces unique hazards, specific controls must be built into the well test facility and its procedures. Every well test is different — the environmental conditions, the facility, the equipment, and the contractors vary from one well test to the next. Any approach to the management of safety must therefore consider all of the variables, and this process must be repeated for every well test.

SAFETY AND COMPANY POLICY

Many resource companies produce vision statements to reflect the most important company policies. Safety vision statements signed by the CEO or company president carry with them the highest level of authority in the organization to demonstrate their commitment to safety. A vision statement typically uses wording to the effect that the safety of employees, other workers, and the public take precedence over cost and operational considerations.

Stemming from this priority, resource companies have developed management systems and practices to help achieve the goals in the company vision statements.

A SAFETY CASE APPROACH

The management of safety varies in parts of the world according to regulations and with company policies and practices. Most formal safety management or risk management processes utilize risk assessment as an integral part of safety management.

The safety case approach described here, though not adopted everywhere, has all the elements that contribute to a comprehensive formal approach to the management of well test safety. Frequent reference is made in this section to a Vessel Safety Case. Not every facility may utilize a Vessel Safety Case but will more than likely have an equivalent risk management plan as a requirement under the facility class certification. If the facility does not have such a management system and enters an area covered by safety case legislation, then the facility owner must develop a Vessel Safety Case in order to proceed with operations.

A Well Test Safety Case Revision forms a subset of the Safety Case for a particular well or campaign of wells. At the top of this hierarchy is the Vessel Safety Case, and the caretaker of this document is the facility owner. Next in the hierarchy of documents, the resource company's drilling department produces a Safety Case revision document that forms an addendum to the Vessel Safety Case and addresses well-site specific information, that is, the drilling program and safety management system interfaces between the rig owner and the resource company. The formal safety assessment in this Drilling Safety Case Revision addresses hazards specific to the well site and drilling operations. Finally, the Well Test Safety Case Revision provides the description of the well test facility, well test-specific safety management systems, and the well test formal safety assessment.

To distinguish the three different documents, we shall refer to them as the Vessel Safety Case, the Drilling Safety Case Revision, and the Well Test Safety Case Revision. Collectively, these documents make up the Safety Case for the well or campaign of wells during the period of the contract between the resource company, the facility owner, and the well test service contractors.

1. Vessel Safety Case
2. Drilling Safety Case Revision
3. Well Test Safety Case Revision

A Safety Case brings together diverse elements from engineering, procedures, and risk assessments, and structures that information into a standardized format. In the process of preparing this documentation, the planning team effectively follows a process that addresses the different aspects of safety management. These documents are often required for submission to a government regulator for approval before operations may commence. Each document is structured similarly into three general sections:

- Facility description
- Safety management systems
- Formal safety assessment

The facility description details physical aspects of safety engineered in the design of facility; the safety management system details the processes utilized to plan and conduct operations; and the formal safety assessment details the level of risk for the various planned operations and how those risks have been reduced to acceptable levels. Various regulations, policies, and standards underpin these and are referenced as required in this chapter. The following lists the type of references found in a safety case.

1. Regulations, policies, codes, and standards
2. Safety management systems, including contractor management systems
3. Well test design and engineering reports
4. Site-specific safety assessments
5. Safety systems inherent in the well test equipment
6. Facility systems utilized in support of the well test safety systems
7. Procedures governing the conduct of the well test

In a resource company organization, both the HSE officer and the well test engineer prepare the Well Test Safety Case Revision, with significant input provided by contractors and departmental team members. The well test engineer organizes and facilitates most of the planning meetings such as the risk assessment for hazard identification and hazard and operability studies.

Significant input to the safety case document is provided by the surface well test service contractor in the form of the well test design and engineering report, while other third parties contribute significantly by participating in risk assessments and providing technical input and specific reports in support of their roles in the operation. The HSE officer and the well test engineer coordinate this input and ultimately prepare the final document for review by resource company management prior to submission to the regulator.

THE WELL TEST SAFETY CASE REVISION

General Information

As a preamble to the well test facility description, a general information section lists the stakeholders in the well test and the facility engaged. This background information is useful to personnel who have not had a hand in its preparation, and it places the document in context for the reader without having to refer to references.

Site-Specific Data

Site-specific information provides details of the well test environment. Location data provides field and well names, license block, formation targets, and well completion information, including well depths and casing and liner data. A list of well and reservoir conditions details fluid types, reservoir, wellbore, and surface conditions, including pressure, temperature, flow rates for each phase, and special fluid characteristics such as hydrogen sulphide, hydrates, wax, carbon dioxide, foam, and heavy oil. The information in the site-specific data section may be tabulated for easy reference.

This information is similar to that provided in the Basis for Design and serves much the same purpose; that is, it describes the well test environment against which the detailed design has taken place.

WELL TEST FACILITY DESCRIPTION

A well test facility description serves a number of purposes:

1. It describes the interfaces between the drilling and well test facility.
2. It describes the engineering input to the design of the well test facility to demonstrate compliance to industry codes and standards.
3. It describes the engineered safety design features of the well test facility
4. It describes the overall well test procedure to show how the facility will be operated.

A well test facility description starts with information providing some detail on each of the main equipment components and ends with a relatively detailed description of the well test procedure. A typical sequence and set of headings within a well test facility description is as follows.

1. Well Test Equipment
2. Equipment Placement
3. Process Facility Description
4. Safety Systems Description
5. Well Test Procedure

Well Test Equipment

A logical order in which to present this information is to subdivide the equipment according to contractor service, starting from the reservoir and ending with the surface equipment. For example,

- TCP
- Downhole tools
- Test string
- Subsea
- Surface

These headings provide detail describing each piece of equipment that will be utilized for the operation. Justification for each selection may be provided here or referenced from another document. Information may be presented in a variety of ways, but typically the report contains a short descriptive text indicating the purpose of any piece of equipment and a table or list of specifications including manufacturing codes and standards applicable to that item. An example of such as table may be found in Chapter 5 Table 5.6 Process equipment list and specification

From a safety assessment point of view, the Well Test Safety Case Revision is most concerned with surface equipment because it represents the greatest exposure for personnel to the hazards associated with the well test. It is usual to provide brief descriptions of the equipment provided in other services and more detailed information for surface equipment, although it is not necessary to provide exhaustive data in this document since that information is provided in the well test design report. References should indicate where detailed technical information could be found.

EQUIPMENT PLACEMENT

Real estate on the deck requires continuous management, never more so than during a well test operation, since well test equipment occupies a considerable percentage of the available deck space. As a first step, a well test engineer should consider the ideal deck placement for the proposed well test against the area normally allocated to well test equipment, if any. Many facilities have designated well test areas, that is, areas designated under the Vessel Safety Case for well testing. Even though Vessel Safety Cases do not provide detailed well test safety management information, they frequently consider well test activity in their formal safety assessment sections, at least for fire and explosion risk analysis, making certain assumptions about equipment location, general well test conditions, and fluids. The formal safety assessment uses quantitative risk analysis techniques in order to build an overall risk assessment for the facility. Any resource company, placing well test equipment outside of a designated well test area, must be prepared to conduct a detailed formal safety assessment and to take appropriate steps in order to reduce any new or introduced risks arising from the nonstandard deck placement. Examples of issues dependent on equipment placement include deck loads, impact on escape routes, fire-fighting equipment, escape equipment, proximity to personnel living and working quarters, and impact on hazardous areas.

A deck plan similar to that provided in figure 6.1 Well test equipment placement is a convenient way of representing the proposed location for well test equipment. A deck plan should include sufficient detail so that all the major components of test equipment can be identified. Other information can be provided separately; for example, the deck load information can be tabulated to indicate footprint dimensions, wet weights for each component, and the deck load capacity in the area proposed for each piece of equipment. Deck load capacity information should be available from the owner in the Vessel Safety Case. Chapter 5 includes a discussion on equipment placement and deck loads, figure 5.22 illustrates an example deck load drawing and 5.23 a table of well test equipment deck load specifications.

Process Facility Description

Well test equipment is essentially a portable production facility; the standards and practices normally applied to process facilities largely apply to the well test facility. This section describes how the equipment is interconnected, what conditions the well test facility is designed to operate within, and how it will operate. It also details the safety devices built into the process.

A short description of the fluid handling sequence through the main components is usually adequate to describe how the process equipment will handle well fluids. Special mention of activities in the separator, such as sampling and metering, indicate where most work activity will take place; disposal of fluids at the burners highlights an activity that requires later attention in hazard identification. A piping and instrumentation diagram (P & ID) will describe the interconnections for the equipment and also provide detail of the equipment safety devices. The P & ID may be included as an appendix to the Well Test Safety Case Revision or more usually, it is referenced in the contractor Well Test Design Engineering Report, where it normally resides. Chapter 5 includes an example of a simple P & ID, figure 5.21 (a) Basic well test P & ID

The HAZOP, or Hazard and Operability study, is the formal assessment applicable to process systems. It is described later in this chapter.

Safety Systems Description

This section describes the engineered safety systems built into the design of the well test facility. The approach is described in terms of a safety system philosophy that identifies three levels of safety.

1. Manual intervention
2. Automatic shutdown
3. Safe relief of pressure

Manual Intervention

Manual intervention — closing a production valve or opening a vent — is the primary means available to personnel operating the process equipment to remedy an unsafe condition. Manual intervention is relied upon to an extent

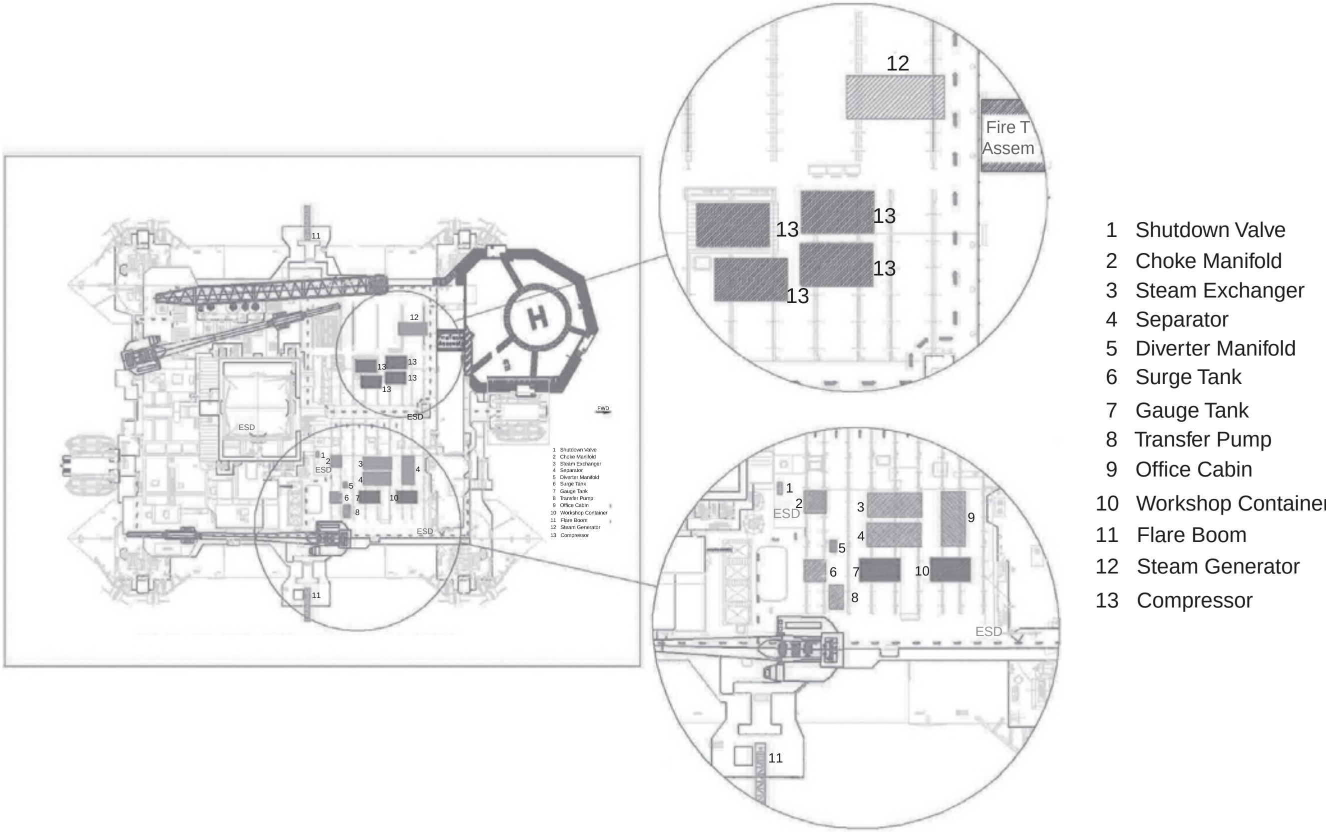


FIGURE 6.1 Well test equipment placement

greater than for production process equipment. This is so because well test processes frequently deal with continuously changing production conditions, separator and tank levels can vary unpredictably if liquid production varies for example. Whereas production processes generally operate under stable conditions. Personnel attending well test equipment take frequent manual measurements. Manual observation of local gauges is supported by electronic sensing devices that trigger alarms if conditions exceed preset values. At any time, if production conditions threaten to become unsafe and manual adjustment is impractical, personnel can operate strategically located emergency shutdown switches that close production valves on the flowhead and upstream of the choke manifold.

Automatic Shutdown

The second level of protection, automatic shutdown, is achieved using sensor switches located at key points in the process, which sense pressure locally and activate the emergency shutdown system in the event operating pressures exceed the preset limits set on the sensor. The positioning of each switch and its settings are indicated on the P & ID drawing. The locations and settings are decided during the HAZOP.

Safe Relief of Pressure

Pressure-relieving devices provide the third level of protection. These devices are designed to vent excess pressure to a safe area if values exceed preset limits. The calibration and suitability for these devices to the conditions is verified in accordance to recognized standards generally API RP 520 Design and Installation of Pressure-Relieving Systems in Refineries, Parts I and II, and ANSI/API Standard 521. Petroleum and Natural Gas Industries—Pressure-relieving and Depressuring Systems. The set point for automatic switches and pressure-relieving devices is selected so as to activate the shutdown system at or before the point where the pressure within any particular segment or component of equipment exceeds the safe working pressure of that segment or component.

The settings and locations for pressure relieving devices is decided during the HAZOP. Reference standards for the HAZOP are API RP 14 C Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, and, the European HAZOP process.

The description of the process safety system includes a description of the ESD system, which provides the primary means for shutting down the well test in an emergency. The description must include the reaction time for the ESD to shut the production valves.

Well Test Procedure

The well test facility description has thus far described the individual components of equipment, their order of assembly, and the engineered safety systems built into the design. The final section of the facility description provides

detail as to the procedure for installing and conducting the well test, to demonstrate how the facility will be used. The level of detail required should be sufficient to indicate the main sequence of operations and the schedule for the test, including the flow periods. The appendices include a sample basis for design document which includes a table of the type that can be used to outline the well test procedure.

This information provides input to the hazard identification process, which assesses hazards for each operational step and also provides input to the fire and explosion analysis based in part on the duration of the flow period.

SAFETY MANAGEMENT SYSTEMS

Safety Management Systems (SMS) are processes that are not necessarily specific to well tests. However, the well test is a process governed by safety management systems. Most resource companies have safety management systems that include processes for managing a wide range of activities. This section of the Well Test Safety Case Revision provides details on how those processes apply to the well test. The reader will recall that the Well Test Safety Case Revision is the third in a three tier-hierarchy of documents. The Vessel Safety Case includes details for the MODU owner safety management systems, whereas the Drilling Safety Case Revision details how the resource company safety management systems interface the MODU owner systems. This section of a Well Test Safety Case Revision, simply reviews the corresponding sections in the Vessel Safety Case and the Drilling Safety Case Revision, and appends to each any specific well test controls or variations.

The following lists some of the elements frequently found in safety management systems and provides some background discussion for each in order to better explain how these elements are addressed in a typical Well Test Safety Case Revision. In particular, some of the safety processes frequently developed for well testing are identified and integrated into a safety management system. The examples selected have a particular bearing on well test operations.

- Contractor Management
- Audit and Review
- Management of Change
- Design and Construction
- Personnel Competency
- Emergency Response

Contractor Management

Contractor management is an element of almost every safety management system, detailing the processes and procedures developed by the organization to manage contractors. Examples of some of these processes include contractor technical and safety qualification, contracts management, and contractor inductions. Contractors represent a significant risk to a resource company because many of the activities that the contractor performs on behalf

of the resource company fall outside its control — for example, the hiring and training of contractor personnel and the procurement of material and hardware for specialized applications. Well testing in particular is a contractor-dependant operation and for this reason alone it represents considerable risk to the resource company. The section on contracts in the previous chapter includes a description of the contractor qualification process in which the resource company assesses the management systems for each of its contractors to ensure that their systems meet standards acceptable to the resource company. The assessments consider safety, technical, and commercial aspects of a contractor's management systems. After contract award, subsequent audits and inspections by the resource company monitor the contractors to ensure their safety management systems are being implemented and followed.

CONTRACTOR SAFETY MANAGEMENT SYSTEMS

In the same manner that resource companies utilize safety management systems to reduce risk, contractor companies have their own safety management systems. These systems reference standards and procedures that the contractor adheres to and which are specific to well test activity. For example, many well test contractors have standards relating to working with pressure, explosives, hydrogen sulphide, nitrogen, and for working at heights or over water. Other standards cover the training and competency of personnel, the procurement of materials, manufacturing, and ordering. Provided the standards are industry recognized and that audits and inspections show that those standards are adhered to, the resource company has an increased level of confidence that the risks in relation to activities performed by their contractors are adequately managed.

This section of the safety case references any safety management system process that the resource company will apply to the management of its contractors.

Audit and Inspection

Audit and inspection are quality assurance tools; in practice, there is often little difference between the two other than that an audit is performed by a qualified auditor and is usually more formal than an inspection. Both tools provide verification that any claims that contractors make with respect to how they manage safety are true. Resource companies frequently audit their contractors to ensure adherence to their management systems. Any deficiencies in contractor processes are identified in a report. Significant issues require immediate remedial action, whereas minor deficiencies are tracked for resolution during the normal course of planning. During a drilling campaign, the resource companies often set HSE objectives that include a minimum number of contractor audits. These objectives are detailed in the Drilling Department Safety Case document.

Specific audit and inspection processes relating to the well test are identified in the Well Test Safety Case Revision, under the Audit and Inspection heading. Inspections link the content of the well test safety case document to the physical

equipment supplied. In addition to contractor management system audits and equipment inspections, in parts of the world resource companies are required by regulation to perform a detailed design review of a well test by an independent party to provide a thorough check of a particular design's suitability. The appendices provide an example well test inspection guideline.

Management of Change

The industry has long recognized that HSE risk levels increase when operations deviate from their planned course. The greater the complexity of an operation, the greater is the risk that a change in the planned course of action might result in an HSE incident. A well test is directed by a detailed set of procedures contained within the Well Test Program. Other procedures, including contractor procedures, also contribute and are referenced in the program. The procedure for the well test represents a considerable input of planning from the planning team; it has been subjected to reviews and risk analysis to verify its suitability. But for all of that planning, it is not unusual that some aspects of the procedure will require modification at the well site. In some cases, entire sections of the program require revision in response to some unexpected behavior in the reservoir or to some unforeseen technical issue. Sometimes these issues only come to light just prior to, or during, the course of executing a particular task. Given the high operating costs associated with drilling facilities, personnel must resist the temptation to implement changes without due consideration. Management of change is the name applied to the process whereby resource companies control changes to the program. It includes guidelines on the type of changes that require personnel to stop and follow an assessment and approval process before proceeding. The process also details the authorities required to review and approve such changes. The Management of change process referenced in a drilling department safety case is often identical to that process used for well testing, in which case the Well Test Safety Case Revision need only refer to the drilling department management of change process.

Design and Construction

The facility owner governs the design and construction element of the Safety Management System. Class-certifying bodies and the Vessel Safety Case mandate that modifications and additions to the facility must comply with applicable engineering standards, including temporary additions such as a well test facility. An objective of the Well Test Safety Case is to demonstrate compliance with this requirement. This objective is achieved with the well test facility description, the process analysis, and the well test engineering report.

Personnel Competency

Both the owner and the resource company will include personnel competency elements in their SMS, as well as measures to ensure that personnel are adequately

trained and fit to perform their respective tasks. The facility owner's SMS details the responsibilities and competency measures applied to the facility crews, rig superintendents, drillers, roughnecks, crane operators, radio operators, marine crew, mechanics, catering crew, and so on. The drilling SMS will detail the measures to control competencies for resource company representatives and contractors employed directly by the resource company for the operation (i.e., drilling supervisors and contractors). The well test SMS will provide the same detail in relation to the well test engineer and those contractors engaged specifically for the well test.

The facility owner's SMS measures include training for technical and HSE competencies; examples include well control certification, fire fighting, helicopter deck operations, man overboard, first aid, man riding, and permit to work.

The well test SMS will detail contractor HSE and technical training, together with a process to review the competency of personnel prior to traveling to the well site. This might simply involve a review of personnel CVs and training records. Resource companies often brief contractor personnel prior to operations as part of their competency training measures to ensure that all personnel are aware of their roles and responsibilities.

Emergency Response

The SMS in every Safety Case document references emergency response plans that describe the contribution to emergency response by the facility owner and the resource company, and in the case of the well test document existing plans to manage emergencies in relation to well test activity.

Emergency response plans are standalone documents that provide procedures to mobilize resources in response to different emergencies. Those resources include emergency response teams located at head offices or support facilities. The emergency response teams have access to further resources; for example, transport, medical equipment and supplies to be mobilized in support of the well-site facility during the emergency. The plans also detail lines of communications and define roles and responsibilities in the event of an emergency. The resource company prepares such plans, with the drilling and HSE departments usually working with the drilling contractor in order to interface with the contractor equivalent document.

The Vessel Safety Case references the facility owner's plan, providing a general description of the document scope, that is, the types of emergency and the controls in place for dealing with each. Table 6.1 provides a list of the emergency conditions typically listed in a plan and the corresponding controls.

Well test planning does not normally require a dedicated emergency response plan; instead it references the drilling contractor and resource company plans, detailing what aspects of those plans apply to the well test and any additional controls. Table 6.2 Well test emergency response controls lists additional controls appended to the drilling controls that are specific to well test operations.

The roles and responsibilities of the well test crew must be agreed upon during planning and must be clearly communicated to the well-site crew. With the exception of weather extremes, the well test crew typically responds as follows

Table 6.1 Drilling Emergency Response Controls

Condition	Control
Blowout	BOP Diverter Kill weight fluid
Fire and explosion	Fire teams On board fire-fighting systems Blast walls
Weather extremes	Emergency evacuation plan Operating parameters Emergency well suspension procedures
Oil spill	Oil spill contingency plan

Table 6.2 Well Test Emergency Response Controls

Condition	Emergency Controls	Well Test Specific Controls
Blowout	BOP Diverter Kill weight fluid	Test string design (valve barriers)
Fire and Explosion	Fire Teams On board fire-fighting systems Blast walls	Well test specific fire and escape plans Well test emergency drills Fire-fighting equipment specific to well test needs
Weather Extremes	Emergency evacuation plan Operating parameters Emergency well suspension procedures	Well kill procedures Emergency disconnect
Oil Spill	Oil spill contingency plan	Spill containment and spill absorbent equipment

1. Shut in production (activate ESD).
2. Stop transfer pumps.
3. Shut down steam boiler.
4. Shut down compressors.
5. Proceed to muster station.

Weather extremes involve a well kill and subsea tree (SSTT) unlatch. Typically, for an emergency unlatch,

1. Stop production (activate ESD).
2. Open kill valve and bullhead kill fluid to SSTT.
3. Close SSTT.
4. Unlatch and retrieve upper string.

FORMAL SAFETY ASSESSMENT

Risk cannot be reduced to zero, but with adequate safeguards it may be reduced to an acceptable level. A formal safety assessment is a process used to evaluate risk and to identify controls to reduce risk to ALARP (as low as reasonably practicable). Put another way, the organization can justify committing money and resources to add safeguards to reduce risk level up to the point where the money and resources committed outweigh the value of doing the operation.

A formal safety assessment uses qualitative techniques that follow established methods to assess risk. During this process, significant hazards, especially those that have the potential to result in fatalities, are singled out for further detailed assessment or quantitative risk analysis. Quantitative risk analysis techniques utilize statistical information derived from historical data to help arrive at a refined measure of risk. The process also helps develop more detailed controls to manage this risk.

Qualitative risk assessment for well test operations is carried out using Hazard Identification (HAZID) methodology. Process safety is assessed separately, using Hazard and Operability (HAZOP). The quantitative risk assessment is achieved using quantitative risk analysis (QRA).

Before proceeding further, it will be useful to provide some definitions in order to distinguish some of the concepts that occasionally cause confusion during a risk assessment.

- A *hazard* is that which has the potential for adverse consequences
- A *safeguard* is a control that reduces the likelihood that a hazard will have adverse consequences
- *Mitigation* is a control that reduces the severity of an adverse consequence but does not reduce the likelihood of its occurrence in the first instance
- *Risk* is a measure of the likelihood and severity of the adverse effects of a hazard.

Qualitative Risk Assessment

Qualitative risk assessment employs various tools to gather information regarding an operation and to evaluate that information in order to identify hazards and attribute risk levels. For most steps in a well test operation, this form of assessment is adequate to justify continuing with the operation. Some

hazards may carry a significantly higher level of risk. Due either to the severity potential of the consequences or to the probability of adverse consequences, these hazards may require further detailed assessment in order for the resource company to better understand the risks and justify proceeding with the operation. This approach is discussed in the section on Quantitative Risk Assessment later in this chapter.

HAZID — Hazard Identification

The HAZID process, though not the only tool available, is probably the most widely utilized qualitative risk assessment technique. Information in a HAZID is captured and presented in table format. A HAZID concerns itself primarily with those aspects of an operation that may have adverse health and safety consequences, although this tool may also be used to assess other risk categories such as risks to the environment, reputation, and cost. The planning team must define the scope of the HAZID to ensure that those participating are focused on the category of risk the resource company requires.

ASSEMBLING A HAZID TEAM

For the assessment to have value, the participants must include representation from the stakeholders in the well test. These include the resource company planning team, the MODU owner, and the well test service contractor. Other individuals who may add value include government regulators, the reservoir engineer, and representatives from other service contractors.

HAZID FACILITATOR

An independent facilitator is often utilized to direct the session. This role is an important one; the facilitator polices the session to ensure that discussion remains focused on the subject at hand and that each step is assessed consistently. The facilitator also produces a HAZID report, which is the official record for the session and captures minutes, recommendations, attendees, and HAZID data. Most of the data is captures in a HAZID worksheet, a sample of which has been provided in Table 6.3 Sample HAZID worksheet.

DEFINE THE OPERATIONAL STEPS

Operations are listed in steps; the level of detail required a reflection of the number and type of hazards associated with each step. For example, when transferring equipment from a supply vessel onto the deck of a MODU, it is not necessary to list all the equipment. The hazards are the same for each item and relate to dropped objects and swinging loads. The first column of Table 6.3 lists a number of well test operations that would likely be included in a risk assessment.

IDENTIFY HAZARDS, CONSEQUENCES, AND CONTROLS

For each operational step the team, referring to their experience and to previous HAZID studies or to checklist tools, identifies the hazards associated with each step. Even if some steps overlap and hazards listed for one appear similar

Table 6.3 Sample HAZID Worksheet

Operation	Hazard	Consequence	Safeguards	Mitigations	Risk
Transfer equipment to and from supply vessel	Dropped objects Swinging loads	Injury or fatality Damage to equipment	Lifting certification Lifting procedures Deck plans	Restricted access	High
Deck placement	Excess load on deck Restricted access Trip hazards Manual handling	Tripping/falling injuries Manual handling injuries Damage to equipment Blocked escape route	JSA Layout plan Contractor SOP Deck load calculation Equipment Certification Pressure testing procedures	Fire and escape plan Wellsite checklists	Low
Work at heights or over water	Dropped objects Falling	Injury or fatality	Permit to work JSA Temporary scaffold	Safety harness Fall arrestor Restricted access	Low
Diesel transfer operations	Burst hose or seal Overfilling tanks Misdirected flow	Fire and Explosion Environmental spill	Permit to work JSA	Tank bunding Oil spill response plan	Low
Production operations	Equipment failure under pressure Misdirected flow Toxic fluid	Injury or fatality Fire and explosion	Permit to work JSA & detailed job brief Contractor SOP Pressure testing Equipment certification	Fire and escape plan Emergency response plan Oil spill response plan	High
Flaring	Inadequate cooling system Flame failure Excess noise	Fire and explosion Environmental spill Hearing damage	Permit to work JSA and detailed job brief Contractor SOP Heat and noise plan	Fire and escape plan Emergency response plan Oil spill response plan	Low

to others, these can be grouped later. The possible consequences are listed in the second column of table 6.3, followed by controls which are distinguished as safeguards and mitigations in the third and fourth column. A number of guidelines must be followed in order that the exercise can add value to planning.

1. Information input to the form must be based on credible scenarios. For example, while it is possible that an individual could have a fatal accident from tripping over a piece of pipework, it is more credible to consider that such an event at worst would result in a first aid or minor injury.
2. One should input as safeguards or mitigations only those that exist and that will be applied at the well site. If a new safeguard is proposed that is not yet in place, for example, an additional piece of safety equipment, then this should be recorded in the minutes of the meeting as a recommendation. It is not a safeguard until it has been written into procedures, ordered, and available at the well site for use.

RISK ASSESSMENT

Resource companies utilize risk levels to group hazards so that adequate planning resources can be directed at areas that present the greatest risk. The process for managing hazards with high risk levels, for example, those that have a high potential for fatality consequences, involves additional assessment using quantitative risk assessment. Such hazards may also require special high-level management approvals and auditing measures to ensure that all of the safeguards and mitigations are fully implemented.

A risk matrix is a common tool used by resource companies to categorize risk levels. The example below is typical of that used by an assessment team. The matrix plots likelihood against consequence, and where these intersect the resource company defines a risk level. In order to assist in the selection of appropriate likelihood and consequence levels, some additional tools in the form of tables provide guidance for assessing a particular risk level.

Table 6.4 provides guidance to determine the likelihood of an adverse consequence from a hazard, and Table 6.5 provides guidance to determine a credible consequence severity for a number of risk levels. As stated previously, the

Table 6.4 Likelihood Guidance

Probable	Will occur in almost every instance
Frequent	A likely outcome in more than half the instances of occurrence
Infrequent	An outcome in less than half the instances of occurrence
Rare	Unlikely outcome about 1 in 10 cases of occurrence
Remote	Unlikely outcome, occurs only in the most exceptional circumstances

Table 6.5 Consequence Guidance

	Health and Safety	Environment	Business Reputation	Cost
Critical	Fatality	Permanent and extensive damage to the environment	Damage to international business reputation, high-profile media exposure, and regulatory attention	> $100 m
Major	Permanent injury or extended absence from work	Extensive damage to an environment involving prolonged recovery period requires significant cleanup intervention	Damage to business reputation, nationally high-profile media exposure, and regulatory attention	> $50 m and < $100 m
Moderate	Injury requiring evacuation from well site. Medical treatment, absence from work, rehabilitation	Recoverable damage to an environment requires some cleanup intervention	Damage to business reputation within the industry, no significant media attention	> $10 m and < $50 m
Minor	Injury requiring medical treatment, less than 1 day off work	Localized damage, no medium or long term consequences. May require some cleanup intervention	Localized damage to business reputation, no media or regulatory attention	>$1.0 m and <$10 m
Insignificant	First aid treatment only	No significant damage to local environment, can be reversed with some cleanup intervention	Insignificant damage to reputation	<$1.0 m

Table 6.6 Risk Ranking Matrix

	Insignificant	Minor	Moderate	Major	Critical
Probable	Low	Low	High	Very High	Very High
Frequent	Very Low	Low	Medium	High	Very High
Infrequent	Very Low	Low	Medium	High	Very High
Unlikely	Very Low	Very Low	Low	High	Very High
Remote	Very Low	Very Low	Very Low	Very Low	Low

planning team must define the scope of the HAZID. For example, the assessment might only require consideration of risk to safety and the environment, ignoring other categories such as financial risk. When selecting from each table, consider that the objective is to define credible likelihood and consequence levels given the controls in place.

Table 6.6 is a risk matrix, plotting likelihood and consequence to arrive at a resource company's defined risk level. Higher levels of risk require greater business justification and authority to proceed. A risk level of Very High might require a business justification, quantitative risk analysis, and executive approval.

The HAZID process is applied to each of the operational steps for the well test. At the end of this process, the HAZID will have defined recommended controls for each hazard and a corresponding risk level. Depending on company policy, some of those hazards associated with high or very high risk levels will be singled out for further detailed assessment, possibly using quantitative risk assessment processes.

Some other recommendations or unresolved issues will also be recorded; these may include recommendations to research a particular issue further or to verify that a particular process is required. These actions and recommendations will be listed in a HAZID report issued by the facilitator. The report should include the following as a minimum:

- List of attendees
- Overview of well test operation
- Description of the methodology used for the HAZID
- Completed set of HAZID tables for every operational step
- List of recommendations and actions

Implementation

The HAZID exercise would be valueless without some process in place to ensure that recommendations and actions from the meeting are fully implemented. Many of the controls for each step may already exist and the processes to ensure their implementation may be in place. However, those controls recommended by the HAZID team, but not yet implemented within the safety management systems of any of the stakeholders, require special attention.

Two additional safety management tools come into play at this point: the risk register and the action tracking process. The output from every HAZID is recorded into a risk register. A risk register may be a database or a collation of the reports recording the results from all previous risk assessments. Along with the risk register or incorporated into it, all resource companies maintain an action tracking system. Action tracking details each of the actions from the risk assessment and assigns them to a responsible individual for closure. The actions and recommendations are assigned to individuals within the resource company organization and remain open until the relevant control or until change to an existing control has been implemented in the resource company safety management system. A Safety Case will not be approved by management or by the regulator if any of the HAZID actions are outstanding.

HAZARD AND OPERABILITY HAZOP

The HAZOP is a qualitative risk assessment tool applied to process systems such as the well test package. Using a set of guidewords to list process deviations that may have undesirable consequences, a team of specialists lists the possible hazards arising from each undesirable event and identifies controls to prevent the undesirable event or to protect the system should it occur. The set of guidewords listed below is typical of that used in a HAZOP exercise.

- Overpressure
- Underpressure
- High flow
- Reverse flow
- Excess temperature
- Low temperature
- Liquid blow by
- Gas blow by

Methodology

A HAZOP is conducted as a meeting that brings together a team of personnel with the necessary experience to evaluate the well test process equipment. Generally, this team will consist of the well test engineer, representatives of the well test contractors, the MODU owner, and the company safety department and sometimes a representative from the regulatory authority. A facilitator experienced in directing a HAZOP session is often utilized to police the meeting and generate the necessary reports on the meeting outcomes.

In preparation for the HAZOP, the well test process equipment is divided into smaller sections, referred to as nodes. Each node is a section of the process equipment sharing the same specification and protected by the same safety devices. An example list of nodes for a typical well test system is as follows.

- High-pressure pipework
- Medium-pressure pipework
- Low-pressure pipework
- Steam exchanger
- Boiler
- Separator
- Low-pressure tank(s)
- Transfer pump(s)
- Injection pump(s)
- Compressors

A piping and instrumentation diagram (P & ID) and a safety analysis table (SAT) are two tools utilized to aid in the HAZOP process.

Piping and Instrumentation Diagram (P & ID)

The P & ID is a representation of the entire well test process equipment package on a single drawing or set of drawings. It includes every element of the process, notably:

- Instrumentation: meters, gauges, indicators, switches, valves, etc.
- Piping: high pressure, low pressure, size, type, end connections
- Process equipment: vessels, pumps, compressors, burners, boilers, exchangers, etc.

In addition to identifying the process equipment components down to the individual instrument level, the P & ID also indicates the location of each component in relation to the rest of the process. This order is important to ensure that the assembled equipment reflects the design agreed upon by the planning team. For example, a low-pressure safety device accidentally situated in the wrong location may be exposed to a high pressure and activate unnecessarily, resulting in an avoidable shutdown. Alternatively, the device may end up located on the wrong side of a valve, which is normally closed during operation, resulting in the isolation of that safety device and reduced protection against overpressure in that node. In the same way, the P & ID also indicates the configuration of the process equipment, the order of the process equipment, and how it is interconnected. This helps to identify interfaces between components of the process equipment; for example, interfaces may include crossovers between different pipe sizes or flange connections to rig supplied equipment.

Because a P & ID represents a complex system in detail, it is important to represent it in as simple and readable a format as possible using standardized symbols to represent the different elements. A number of standards are available from various organizations such as ISO, API, and ISA.

The P & ID diagram is prepared by the surface well test contractor and reviewed by the planning team during the HAZOP process. The final revision includes the outcomes from the HAZOP process and is included as part of the

well test design report prepared by the surface well test contractor. A simplified P & ID is illustrated in Chapter 5, Figure 5.21 Basic well test P & ID.

Safety Analysis Table

The SAT table captures the information gathered from the HAZOP meeting. A SAT table is produced for each node of the well test equipment. In the first column of the SAT table the guidewords applicable to that node are listed. In the second and third columns of the SAT table the cause and observed process deviation are identified, the last two columns of the SAT table list the controls that protect the process from the process deviations. The controls adhere to the safety system philosophy. Table 6.7 is an example SAT table that analyzes a well test separator as a HAZOP node.

The controls listed in this SAT table include a combination of safety devices which protect the separator and also include reference to notes which indicate the process is continuously manned or that the process deviation does not present a significant hazard. Re-visiting the safety system philosophy.

1. Manual Shutdown
2. Automatic Shutdown
3. Pressure Relief

In level 1, Manual Shutdown, the process equipment is continuously attended and monitored. On-site personnel can detect abnormal system conditions and take remedial action or shut down the process as appropriate. In order to satisfy this level of protection, the process must include devices at each node which permit monitoring of conditions and the facility for operators to shut down the process quickly in the case of emergency. The P & ID identifies pressure, temperature and level indicators on the separator to satisfy this requirement.

Level 2, Automatic Shutdown, provides for sensors fitted to each node of the process equipment, which detect abnormal states and react automatically to shut down production. Devices can be added to detect and react to extremes of pressure, temperature, liquid level, excess flow, and reverse flow. In the case of the well test separator high and low pressure switches provide the automatic shutdown to achieve this level of protection.

Level 3, Pressure Relief, requires calibrated pressure-relieving devices fitted to protect every part of the process that may be subject to excess pressure. The standards governing the use of these devices also include rules for relief pipework size and routing. The separator vessel is fitted with dual pressure relieving devices to satisfy this requirement.

HAZOP Report

The outcomes of the HAZOP are captured in a HAZOP report containing

- List of attendees
- HAZOP objectives

Table 6.7 SAT — Well Test Separator

Guideword	Cause	Process Deviation	Control 1	Control 2
High pressure	Blocked line, Incorrect valve operation	Rupture, leak, spill	High-pressure switch	PSV 1 and 2
Low-pressure	Leak	Back pressure	Low-pressure switch	None-Note 1
	Blocked inlet	Reverse flow		
High liquid level	Blocked line	Liquid overflow	Note 2, 3	Note 2, 3
	Incorrect valve operation			
Low liquid level	Leak	Gas blow-by	Flow restrictor, Note 2	Note 2
	Incorrect valve operation			
High flow	Rupture	Erosion	Note 1, 2	Note 1, 2
	Incorrect valve operation	Leak		
Excess temperature	Boiler malfunction	High temperature	None, Note 4	None, Note 4
	Low flow			
Low temperature	Boiler malfunction	Low temperature	None, Note 5	None, Note 5
	Gas hydrates			

Note 1: Downstream components vent to flare, no significant pressurized volume stored downstream.
Note 2: Separator level varies during operation due to slugging nature of production, Separator operation is continuously attended.
Note 3: Downstream components can safely handle the maximum liquid throughput.
Note 4: Separator maximum allowable working temperature is greater than the maximum possible temperature generated in the fluid.
Note 5: Separator minimum operating temperature is lower than the lowest expected fluid temperatures during production.

- Operating envelope and list of guidewords
- Description of the process followed
- P & ID
- Set of completed SAT tables
- List of recommendations and action, which may include changes to the process, process controls or changes, and additions to procedures

The HAZOP facilitator generates the HAZOP report.

HAZOP References

API RP 14 C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms and the European Process Safety Centre in their Guide, "HAZOP — Guide to Best Practice" provide reference standards for this process.

QUANTITATIVE RISK ANALYSIS

Quantitative risk analysis, (QRA) provides a more precise measurement of risk in terms of safety, environment, reputation, and cost. In doing so, it helps to define more effective controls. Quantitative risk analysis requires greater planning effort than qualitative risk analysis and is generally utilized only in areas associated with high or very high risk. With regard to well testing, very high risk generally involves those activities that may result in one or more fatalities, fire and explosion, and toxic release. Detailed quantitative risk analysis is a specialized area that involves third parties performing the detailed analysis itself. The description that follows is intended to introduce the subject and to indicate the role of the well test engineer in providing input to this process.

Fire and Explosion Analysis

Fire and Explosion Analysis (FEA) is a detailed assessment of the particular risk for fire and explosion. FEA considers the conditions that give rise to this possible consequence and applies statistical modeling to arrive at a quantitative probability for its occurrence. Data from the model can be used as input to further studies that will identify additional controls or refinements to planning that provide an overall reduction in risk.

The statistical modeling is based on the historical data available for leaks due to seal failure, metal fatigue, or human error. The probabilities also consider the production duration, the longer and more numerous the flow periods the greater the likelihood of a leak occurring.

Some Terms Used in Fire and Explosion Analysis

Jet and Spray Fires: Turbulent flames produced by the combustion of hydrocarbon liquid or gas escaping from a source under pressure. These

fires produce significant heat radiation and can cause structural failure on surfaces contacting the flame. This can give rise to other problems that can escalate the condition. Jet and spray fires vary according to the type of fuel, the conditions giving rise to the escaping fuel, including fuel pressure and leak size, duration of the leak, proximity to personnel, equipment, structures, and the external conditions of wind and degree of enclosure. Jet liquid fires can produce significant quantities of black smoke, which can lead to other problems relating to reduced visibility, toxic inhalation, or suffocation.

Liquid Pool Fires: Fires associated with flammable liquids at atmospheric conditions, either contained or spread over a surface. In general, the same volume of liquid spread over a large surface burns more rapidly and generates more heat compared to the same volume contained within a space such as a tank to present a smaller surface area to the atmosphere. The surface area of a liquid pool fire will continue to increase until physical barriers on the deck contain it. The leak size and the fuel available to feed the pool contribute to the duration and size of a liquid pool fire.

Blast Radius: Every area extending from an explosion source which experiences the effects arising from that explosion. The shock wave generated by the explosion produces an increase in pressure and temperature, which dissipates rapidly with increasing distance from the source. FEA modeling calculates the intensity of the energy produced by a potential explosion source, based on the fuel type and other conditions, such as stored volumes and pressures. The heat energy at various distances from the source can be plotted on a chart. Various energy intensities of interest are noted on the chart to examine their impact on personnel, escape routes, temporary abandonment locations, and safety equipment.

FEA Modeling

Much of the information input for FEA modeling is available from the facility description and the Basis for Design, including type of fluid, pressure and temperature, hydrocarbon inventories on deck, and production rate. This information defines the scale and type of a possible fire and explosion event; the production period, and the overall number of well tests planned help to determine the probability of an FEA incident. The location of the equipment on deck is important in establishing the center of any blast radius or pool fire source. Finally, additional input for the model is based on certain assumptions agreed to by the modelling team, including the well test engineer. A typical set of modeling assumptions are as follows.

- Liquid fuel is assumed to be pantene.
- Gas fuel is assumed to be propane.
- Fuel sources are from leaks in the process equipment, with assumed leak sizes of 10, 25, and 50 mm.

- Jet or spray fires will result if the fuel leak ignites on high-pressure equipment.
- A pool fire will result if fuel leaks from low-pressure equipment.
- The number of personnel present in the well test area at the time of an explosion will be 4.
- The number of personnel present on the drill floor at the time of an explosion will be 2.
- The emergency shutdown will activate within 60 seconds after the leak has occurred.
- The maximum inventory of hydrocarbons will be the sum of the well test vessel contents.
- Ignited fuel from a leak will result in a jet fire lasting 60 seconds until the ESD shuts off the fuel supply.
- Personnel exposed to 37.5 kW/m^2 (3.3 Btu per square foot second) will be fatalities.
- Escape routes and emergency equipment will be compromised within the 6.0 kW/m^2 (0.53 Btu per square foot second) radius.
- Temporary abandonment will be compromised within the 4 kW/m^2 (0.35 Btu per square foot second) radius.

The figures cited in the preceding list are typical of those referenced in the various standards for this type of modeling.

Blast Radius

The modeling information is used to calculate blast and heat intensity data for any distance from the explosion source centered on high-pressure equipment. The calculations also determine the duration of the blast and jet fire associated with the leak and the probable number of fatalities and major injuries. This data also feeds into additional studies to examine the impact of the event on the facility and its ability to survive and recover from such an event. These studies are:

- Evacuation, Escape, and Rescue
- Emergency Systems Survivability

ESCAPE EVACUATION AND RESCUE

Escape, Evacuation, and Rescue are assessed in the Vessel Safety Case using a process that considers different critical emergency criteria and how these criteria are satisfied for the facility. A typical set of criteria is as follows.

1. Alarms and Communications
2. Escape
3. Safe Muster
4. Primary Evacuation
5. Secondary Evacuation

6. Tertiary Evacuation
7. Rescue

The Vessel Safety Case performs this assessment on the basis of normal drilling operations; this assessment does not always include well test activity. The Well Test Safety Case Revision must evaluate the effect of a well test-related emergency on the facility's Escape Evacuation and Rescue criteria and address any areas where those criteria are not adequately satisfied.

Alarm and Communication: All facilities utilize a speaker address system to alert personnel of an emergency condition. A combination of telephone and two-way radio is generally available for use during an emergency for additional communications. For a well test, it may be necessary to enhance this system perhaps using flashing beacons in areas where the noise associated with a well test might render the audio system ineffectual. During a well test-related emergency, the lines of communication from the well test area to the facility need to be established. Often the driller is a focal point to monitor well test radio traffic and to receive messages from the well test crew as to the status of the well test. In other respects, the existing facility alarm system would be utilized for well test-related emergencies.

ESCAPE

Designated walkways around the facility serve as escape routes that provide access from different areas to the muster and abandonment stations. In general, there are at least two separate escape routes, primary and secondary. These escape routes are marked for easy identification and posted with arrows or signs indicating the direction to travel in an emergency. Escape routes are also identified on the station bill, which is a safety plan available at numerous locations around every facility to inform personnel as to their duties during an emergency.

A well test, which has the potential to impair one or more escape routes in an emergency, must include plans to temporarily reroute those escape routes and identify the controls to ensure that the temporary arrangements will be properly implemented. Such changes require risk assessment and facility owner approval.

SAFE MUSTER

One of the first actions in any emergency is to establish that all personnel can be accounted for. In order to facilitate this action and to ensure that personnel are safe during an emergency, all facilities need to designate certain areas as muster points. These are areas to which all personnel report immediately on hearing an emergency alarm. There are some exceptions to this in respect of the fire team and other individuals tasked with specific emergency response duties. The facility owner identifies the muster areas. Planning for a well test must assess whether the safe muster area can be compromised; if so, adequate controls requiring facility owner approval must be implemented.

PRIMARY, SECONDARY, AND TERTIARY EVACUATION

Every offshore facility has plans to evacuate personnel should emergency conditions deteriorate to such a level as to threaten the safety of personnel on board. The unpredictable nature of emergencies mandates that contingency plans be in place in the event the primary means of evacuation is impaired. Most plans entail three methods of evacuation. The primary means is always the safest and fastest, typically featuring helicopter evacuation. The secondary generally utilizes lifeboats, and the third escape ladders and stairwells to sea level to access inflatable life rafts. Well test activity must be assessed to examine its potential to compromise any of these means of evacuation. For example, an explosion in the well test area may damage the helipad if it falls within the radius of its effects. Smoke billowing from a pool fire might also obscure the helideck from a pilot's vision. These factors must be considered, and the planning team must agree on appropriate controls.

RESCUE

Evacuating personnel from the facility does not in itself guarantee their safety; it only removes them from the immediate danger presented by the initial emergency. If personnel evacuate the facility by lifeboat or life raft, however, they must be brought to a place of safety. Every drilling operation offshore utilizes support vessels to take supplies to and from the facility. These vessels have an additional role as standby in the event of an emergency to rescue personnel evacuating from the facility by means of lifeboat or life raft. Although a well test will have no direct impact on a standby vessel, it must be included in planning to ensure that a standby vessel with appropriate rescue equipment is on hand at all times during a well test operation.

Emergency Systems Survivability

Every facility utilizes systems that serve support functions during an emergency. Most of these systems have been identified at different points in this chapter and again throughout this book. Examples include the BOP for well control, the speaker system for alarms and communications, lifeboats for evacuation, fire pumps for fire fighting, and blast walls to protect personnel from explosion and fire. The purpose of this study is to evaluate what impact a well test emergency might have on the effectiveness of existing emergency systems, how those systems might be used for well testing, and how well test specific systems integrate with the those systems for emergencies.

The following steps illustrate the process that is the basis of this form of analysis.

1. Identify the emergency systems from the Vessel Safety Case.
2. Assess each system to evaluate if it can be compromised by a well test emergency.

a. If the system fails safe, then no further action is required.
b. If the system can be compromised, identify alternatives or controls to protect the system.

3. Identify those systems required in support of a well test emergency.
4. Identify emergency systems introduced specifically for the well test.

The data from this type of analysis are summarized in Table 6.8. The table lists a typical set of emergency systems in the first column, with other columns indicating the results of the process followed in steps 1– 4 for each system.

Applying Risk Analysis Data

The formal safety assessment is made up of qualitative and quantitative components each of which provides information on controls to reduce the likelihood of an adverse consequence or a mitigation to limit the severity of those consequences. The information from these studies also influences the location of the equipment on deck, the procedures governing its installation and operation, the safety systems integral to the design or existing at the facility, and the management systems governing the conduct of the operation. The Safety Case, including the drilling and well test revisions, demonstrate that detailed risk assessment has been performed and that adequate controls have been implemented to reduce the risks associated with the activity to as low as reasonably practicable ALARP.

WELL SAFETY CASE REVISION REFERENCES

The Safety Case is generally submitted to regulators for approval. Given the scope of the document it is more usual to include a list of references rather than to attach them as appendices. The following lists indicate a typical split between attached and unattached references to a Well Safety Case Addendum.

Attachments

- Records of planning meetings
- Risk Assessment Reports
- Drawings including the P & ID and deck plan

References

- Vessel Safety Case
- Drilling Safety Case Revision
- Management Systems
- Well Test Program or overview
- Engineering Design Reports

Table 6.8 Emergency Systems Survivability Summary

Emergency System	Function	Vulnerable	Fail Safe	Redundant	Comment
Well Test ESD	Rapid production shutdown	Yes	Yes	Yes	
Escape Routes	Escape from fire or toxic release	Yes	No	Yes	
Alarm System and PA	Internal communications	Yes	No	Yes	
Firewalls and Bulkheads	Protective barriers	No			
Fire-Fighting System	Fire fighting, surface cooling	Yes	No	Yes	Vulnerable only in areas directly affected by explosions
Subsea Test Tree	Rapid production shutdown and emergency unlatch	Yes	Yes	Yes	
Well Control BOP	Well control	Yes	Yes	Yes	
External Communication	Rescue and support	Yes	No	Yes	
Emergency power and lighting	Support emergency systems and evacuation	No			Vulnerable only in areas directly affected by explosions
Helideck	Primary evacuation point	Yes	No	Yes	
Ballast System	Liquid pool fire control	No			

CONCLUSION

The processes described in this chapter does not encompass the management of safety in its entirety, the management of safety exists in every aspect of well test planning and execution, including the basis for design, the application of industry standards, the contracts process, the well test program and so on. Safety is not isolated from other aspects of planning. Instead it is an integral part of it and evaluated along with every other technical planning detail.

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Chapter | seven

Well-Site Operations

CHAPTER CONTENTS

At the well site, the role of the well test engineer takes on a prominent profile. The well test engineer coordinates the activities of well test service contractors and liaises with resource company and MODU management to put into effect the plans and processes prepared for the well test. The focus of this role changes as the operation progresses. Initially, that focus is on logistics, and in this role the well test engineer works with the logistics coordinator at the well site to plan contractor equipment and personnel movements to the MODU. This process continues until the equipment is located in its allocated area on deck. The focus then changes to that of inspection and quality control, as the well test engineer witnesses contractor preparations. These preparations include pressure tests, tool settings, equipment assembly, and subassembly measurements. The role then becomes one of supervisor: the well test engineer directs the critical path activities of the well test, delegates tasks to various contractor specialists, and oversees the installation of the test string and the commissioning steps in preparation for well testing. The well test engineer then supervises a pretest safety meeting and the subsequent production operations, monitoring production data gathering, sampling operations, and data reporting. Finally, the focus of the role switches back to logistics as equipment and personnel are demobilized to their contract agreed points of origin. In parallel with these areas of focus, the well test engineer has a continuous role working with rig management to ensure the implementation of safety management processes and

to work with the drilling supervisor in a support function in the day-to-day management of the facility. The purpose of this chapter is to describe the processes associated with these roles; the order of presentation follows that which would occur at a well site.

WELL-SITE PLANNING TOOLS

The early stages of well-site operations focus largely on logistics — the movement of equipment, personnel, and materials to and from support facilities to the well site. The lookahead and the logistics plan are tools available to well-site personnel in support of this phase of the operation.

Lookahead

A lookahead is a schedule that estimates the timing for critical path operations. It is a useful reference tool, particularly for planning logistics since it helps to anticipate when certain equipment and services will be required.

A lookahead is usually prepared on a spreadsheet by the well test engineer. A brief description for each high-level operational step is listed in a column; for example, a typical well test operational step could include Make up Bottom Hole Assembly. This operation entails the installation of several pieces of equipment following program and contractor-specific procedures. A lookahead does not need to identify each tool or the procedures, only the overall operation or task. In a separate column, the anticipated duration of that step is usually inserted in units of hours. Next, in a separate column, a space is provided for actual time. For example in the step Make up Bottom Hole Assembly, the well test engineer might estimate this step to take four hours. If in reality it takes six hours, the well test engineer enters this time into the actual time column. Finally, the date and time are displayed, calculated from the duration of each step. The date and time calculates based on estimated time until a value has been entered into actual time, which it then uses to revise the entire schedule. For a sample lookahead, see Figure 7.1.

Logistics Planning

At an offshore facility, because materials and equipment arrive in large shipments on supply vessels, the order in which they are loaded and transferred to the facility is important so as to minimize double handling. This process of organization commences during planning with the development of a logistics plan. This plan is of significant value at the well site because the order in which different tasks occur on the critical path does not necessarily reflect the order in which equipment should arrive at the well site. Some equipment requires only a number of hours to prepare; whilst other equipment may require days, some equipment requires very little deck space and other equipment a great deal. A well test logistics plan details a loadout order from the supply base so that

Well Test Lookahead

JOB:	**Sample**
Start Date:	Tue 17-Mar-2009
Start Time:	21:00:00

#	Start Time	Time Plan	Time Actual	Operation
	Install Test String			
29	Sat Mar-21 13:00	1	1	✓ JSA. Rig up to run perforating string and DST tools.
30	Sat Mar-21 14:00	4	4	✓ M/U TOP guns, seal assy, DST tool, 3 jts tbg. Pressure test.
31	Sat Mar-21 18:00	17	19	✓ RIH tubing in singles.
32	Sun Mar-22 13:00	2	2.5	✓ Tag packer. Close rams on painted joint. Pull back and performspace out.
33	Sun Mar-22 15:30	2	2	✓ Make up SSTT. Function test and RIH on landing string.
34	Sun Mar-22 17:30	1	0.5	✓ Make up SSLV. Function test and RIH.
35	Sun Mar-22 18:00	1	2	✓ Install long bails & change out handling equipment.
36	Sun Mar-22 20:00	4	3.5	✓ Make up Flow Control Head and flow/Kill lines. Pressure test.
37	Sun Mar-22 23:30	1		Sting into packer and land off test string.
38	Mon Mar-23 00:30	1		Pressure test annulus. Cycle tools.
39	Mon Mar-23 01:30	2		JSA. Displace test string to under-balance fluid.
40	Mon Mar-23 03:30	1		Final inspection and checks.
	Perform DST			
41	Mon Mar-23 04:30	1		Function test ESD system
42	Mon Mar-23 05:30	1		Rig floor safety meeting. Perf
43	Mon Mar-23 06:30	1		Perform Pre-Flow an
44	Mon Mar-23 07:30	6		Conduct clean
45	Mon Mar-23 13:30	9		Main Sh
46	Mon Mar-23 22:30	18		M
	Tue Mar-24 16:30	24		

FIGURE 7.1 Sample lookahead

the logistics coordinator knows what equipment to load onto vessels and in what order. A detailed list of each item of equipment from every service is placed on a spreadsheet, and a loadout priority is assigned to each. This level of detail is necessary because many items of equipment within each service might only be required for contingency or backup purposes, while others will not be needed until late in the operation. Deck space is limited both on supply vessels and on the MODU. Mobilizing low priority equipment early may cause logistics headaches, use up valuable deck space, and require double handling at the well site. The consolidated loadout list (Figure 7.2) also provides other important information, including individual container identification numbers, a brief description of contents, weights and dimensions.

The logistics plan also provides a personnel schedule to identify what contractors are required at the well site and in what order. Personnel associated with each service must arrive at the well site just prior to their equipment because contractor personnel are responsible for supervising the unloading and positioning of their equipment on deck. However, since it can take some time to position all of the equipment, it is only necessary and cost effective to have one or two contractor representatives at this stage, the remainder of the crew arriving after the equipment has been located in position. This aspect of the mobilization must be flexible, particularly on offshore facilities that can only accommodate a limited number of personnel. The well test engineer must work with the drilling supervisor, the offshore installation manager OIM, and the well-site logistics coordinator to prioritize personnel movements, striking a balance between the need to have equipment prepared for the test

Well Test Load Out List						
Item	Description	Serial #	Weight Kg	Length m	Width m	Height m
1.0	Choke manifold	CM001	2000	2.5	2.5	0.95
2.0	Steam Exchanger	SE002	15000	5.8	2.5	2.6
3.0	Separator	SEP003	16000	6.0	2.5	2.6
4.0	Surge Tank	ST004	6000	7.0	2.4	2.5
5.0	Gauge Tank	GT005	4500	5.5	2.6	2.7
6.0	Steam Generator	SG006	10000	6.0	2.5	2.6
7.0	Compressor	C21	5000	4.5	2.5	2.1
8.0	Compressor	C22	5000	4.5	2.5	2.1
9.0	Compressor	C23	5000	4.5	2.5	2.1
10.0	Compressor	C24	5000	4.5	2.5	2.1
11.0	Office Container	OC007	8000	4.5	2.5	2.5
12.0	Workshop Container	WC008	10000	4.5	2.5	2.6
13.0	Equipment Basket	EB009	10000	6.0	2.4	1.8
14.0	Pipework Basket	PB010	10000	6.0	2.5	1.8
15.0	DST Tools Container	DST015	10000	6.0	2.5	2.6
16.0	TCP Container	TCP016	10000	6.0	2.5	2.6
17.0	Subsea Container	SS017	10000	6.0	2.5	2.6

FIGURE 7.2 Sample loadout list

and the need to ensure that ongoing operations are adequately supported. A convenient method for capturing this process in the plan is to list the personnel required according to some operational flag. For instance, let us assume that it would take four days to prepare a well test equipment package. The logistics plan will flag that personnel must arrive at the well site at least four days prior to the well test. The logistics coordinator can view the lookahead and identify when the well test operation is due to commence and work back four days to plan for personnel to arrive at the well site.

A deck plan showing the location of each item of equipment is included in the logistics plan for reference. This helps facility management to plan ahead to clear the required deck space in advance of the arrival of the supply vessel(s). Failure to do so might result in extended delays while equipment is double handled from one part of the facility to the next.

Other than equipment and personnel, the logistics plan also provides detail for transporting bulk materials, brine, and chemicals, along with special materials such as explosives and dangerous goods. Brine and other chemicals may need to travel in vessels with specially cleaned tanks to avoid contamination with other fluids. Scheduling tank cleaning operations requires coordination with the drilling supervisor because this operation takes time and requires the support vessel to be off site for tank cleaning, which can take more than a day.

The plan, distributed to contractors before the well test operation, provides information of value to contractors, including

- Contacts list identifying contractor focal points
- Important delivery addresses and freight labeling instructions

- Lifting certification requirements
- Equipment manifest requirements
- Personnel check in instructions including baggage labeling and weight restrictions
- Personnel safety training requirements, including helicopter safety training

CREW INTEGRATION

Contractor crew integration is an issue at the outset of most well test operations. Well test crews are often as unfamiliar with one another as they are with the facility, and it can take some time for personnel to fit in with the routine, particularly if contractor personnel have traveled a great distance and come from differing cultural backgrounds. It is not unusual for it to take several days before the well test crew starts to work well as an integrated team. This factor should be considered when allocating the time available to contractors to prepare their equipment. The well test engineer can play a role in helping crews to settle in, using inductions, holding informal briefings, and getting involved with the issues that the crews have to face in order to get set up. This role might also include holding briefings to the MODU crew as to the tasks the well test crews need to perform to prepare for the job at hand and acting as a liaison between parties to get specific tasks completed. This role is particularly valuable in areas where many different contractors have to work together, for example, organizing cranes, facility electricians, and the cementing service to help prepare the well test equipment.

Problem Solving

Every well test operation involves the expenditure of a considerable amount of money and resources whether land based or offshore. When the operation is offshore, the significant cost of the facility amplifies the overall cost of the test. When things don't go according to plan, personnel on site and the support team may place themselves and each other under pressure to act with a degree of urgency. In such circumstances, it is tempting to take short cuts to recover the situation. However, sometimes the most positive thing to do is to pause, at least until a situation has been properly assessed and the planning team has had time to develop a considered solution. Unmanaged, changes to programs and procedures constitute risk in their own right. The safety and technical hazards that may result from any significant change in procedure should be assessed utilizing the resources available, including management of change controls. On site, the well test engineer has access to experienced rig managers, contractor engineers, technicians, and the support teams in town. Regular communication, meetings, telephone conferences, and adherence to best practices generally yield the most successful outcomes. It is particularly important that senior management take a lead in maintaining the focus on safety at such times.

PRESSURE TESTING

Uncontrolled release of pressure carries high-risk HSE consequences. Its prevention is one of the objectives of the well test design, and pressure testing is one of the most important controls applied to equipment to provide assurance that it will safely contain pressure. Most pressure tests are performed using an incompressible liquid such as water, although there are occasions when other fluids might be used. Contractors carry out pressure tests on their equipment prior to mobilization as part of their standard maintenance procedures. The assembled equipment at the well site also requires pressure testing. However, these pressure tests are more complex. A detailed procedure is required to ensure that the tests are performed in the right order and that valves are configured correctly for each test. Pressure testing itself is hazardous since it entails the application of pressure to equipment that is untested. Thus, additional controls are required to minimize the risks associated with this activity. Certain criteria are essential for every pressure test and must be defined in a pressure test standard or guideline:

1. The magnitude of the test pressure
2. The duration for which the test pressure must hold
3. Acceptance criteria, or degree of variation of pressure acceptable
4. The test fluid
5. The method of application

Manufacturers provide recommended test procedures specific to their equipment, which generally do not address pressure testing of that equipment when connected in a system to other equipment. Contractors provide pressure test procedures for well-site operations, specific to the equipment provided by a particular service. Resource companies produce pressure test guidelines to ensure that appropriate controls are applied to every pressure test operation and that the pressure tests are performed to an adequate standard. Resource companies also write many of the pressure test procedures for the well test; these procedures are included in the Well Test Program.

Developing a Pressure Test Guideline

The objective of a pressure test is to verify that a piece of equipment or a number of connected pieces of equipment will safely contain expected operational pressures.

A number of factors can make it difficult to establish a good pressure test: the presence of trapped air within equipment components, the compressibility of the medium used to perform the test, heating or cooling of equipment during the test, the volume of fluid, and the accuracy and range of the pressure recording device.

A pressure test guideline will generally include

- Details of the controls required to minimize the risks associated with pressure testing
- Steps to eliminate, or at least minimize, factors that hinder a good test
- Procedural steps indicating the method for applying pressure and the maximum value
- Acceptance criteria

Well-Site Pressure Test Guideline

The following steps list a typical set of controls for addressing the hazards associated with pressure testing and controlling some of the factors that can complicate or impede a good test.

1. Pressure test operations must be preceded with a safety meeting by those conducting the tests.
   a. The safety meeting must address communications, permits, barriers and details of the procedure
2. Pressure test operations require a permit to work and must satisfy any of the controls identified in the permit.
3. The procedure must include steps to remove all air and other contaminating fluids from the system prior to a test.
4. With certain exceptions all pressure tests shall be performed using an incompressible nonflammable medium (i.e., water). There may be occasions when water might not be suited. For example, a water–glycol mix is permitted to pressure-test equipment where the test fluid might later come in contact with gas and trigger the onset of hydrates.
5. The general test pressure, which applies to high-pressure equipment only, shall be 20 percent above the maximum expected shut in tubing head pressure SITHP.
6. A calibrated pressure-recording device shall be used for all pressure tests, and a current calibration certificate must be submitted to the well test engineer along with the record of the pressure test.
7. Pressure must be applied in at least two stages: low pressure initially followed by high pressure. Typically, a 5-minute duration low-pressure test at about 10 percent the value of the maximum test pressure will suffice.
8. Maximum test pressure shall be applied to a predetermined value, which will not exceed the safe working pressure of any of the components to be tested.
9. Where stated in the procedure, all pressure tests must be witnessed by the well test engineer.

Pressure Test Acceptance Criteria

Pressure test acceptance criteria generally have two components: hold duration and an acceptable pressure drop profile. The hold duration should be adequate to allow sufficient time to detect a leak or to provide evidence that there is none, but it should not be of excessive duration such that unnecessary time is consumed conducting multiple pressure tests. For small volumes, of the order of liters, a 5-minute test may be considered sufficient. A leak in such a volume should become apparent almost immediately, provided the fluid used is incompressible. Above this volume, 10 minutes is adequate for most pressure tests, although many operators specify 15 minutes. Anything above this is rarely practical.

With regard to pressure drop profiles, a straight-line graph with no pressure drop whatsoever is sometimes difficult to achieve, particularly in a large system. This does not mean that it is not possible to detect a leak. A straight line may be impractical due to trapped air that cannot be removed from some systems or due to thermal expansion and contraction. At high pressures, clouds passing in front of the sun can change the way a pressure test is recorded because it may only take a small change in temperature to produce a noticeable change in pressure. In practice, most standards accept some drop from the initial value but require that the pressure profile show a stabilizing trend. A leak from a system small or large would show a continuous dropping trend. In this manner, a reduction in pressure due to a leak can be distinguished from a reduction in pressure due to other causes based on the pressure test chart profile.

From this discussion, the acceptance criteria specified in a pressure test standard might take the following form.

Pressure tests shall be of 10 minutes duration and shall be considered acceptable provided that the overall pressure drop does not exceed 1 percent of the initial applied test pressure over the 10-minute duration and the drop profile recorded on the recording device shows a decreasing trend.

Exceptions to a company-generated standard will exist for contractor equipment that may require very specific pressure test procedures. The elements of a pressure test standard, listed above, might include a provision that contractor procedures will apply in these cases.

WELL TEST PROGRAM

A Well Test Program is a document prepared by the well test engineer comprising a set of procedures and references that govern the conduct of a well test. The program is available at the well site to all contractors and resource company personnel involved with the well test. The procedures provided in the program cover critical path tasks such as installation of the test string, production of well fluids, and well kill. The program also

provides procedures for the preparation of test equipment on deck offline. The program document is normally sectioned, each section addressing a specific task.

The program contains reference information in support of the procedures. Reference information can include equipment specifications, drawings, and well data, and can also include contractor procedures that form activities within a particular task. For example, the program will detail a procedure to install the test string, but within that procedure the program may refer to a particular contractor procedure to set the packer.

Elements typical in a well test program include

- Overview
- Well and reservoir data
- Well test objectives
- Well status assumptions
- Roles and responsibilities
- Preparations
- Preassemblies
- Test string installation
- Commissioning
- Establishing an underbalance
- Perforation
- Cleanup and flow periods
- Well kill and test string retrieval
- Contingency procedures
- References (drawings, tubing data, offline procedures)

The structure within each procedure is similar

- *List of references,* which include contractor procedures, diagrams, and running tallies. References may be located in the appendices to the program or in external documents. Generally, the most important or most frequently referenced are included in the appendices, unless they constitute substantial documents in their own right.
- *Responsibilities,* which identify the key personnel responsible for directing each procedure. For example, the TCP specialist is identified as the person responsible for directing the assembly of the guns and firing heads on the drill floor.
- *Checklists,* which provide a useful tool to ensure that the preparations required for any specific procedure have been completed. For example, when preparing to run the test string, a checklist might be included to remind personnel to have well control crossovers and special handling equipment to hand prior to commencing the operation.

- *Toolbox meetings,* which are held at every point in the operation when a new task commences, or when some activity within a task has new and specific hazards associated with it. The procedure must identify the need to stop and conduct a meeting as a procedural step.
- *Procedure steps,* which are set out in the order that they should occur. Reference information is often included along with each step — for example, the running order of the test tools, together with a reminder as to the tool settings and running speeds. A certain degree of judgment is required when supplying supporting information to a procedural step. On the one hand, it is not desirable to clutter the procedure with too much information, thereby making it difficult to follow. On the other hand, owing to its high visibility, some important reference information can usefully be given a high profile within the procedure in this manner.

A sample well test program is provided in the appendices.

Overview

The overview is a brief outline of the Well Test Program. It can be of value to those who have not previously been involved with planning but have become involved with the well test for the operational phase and wish to learn what they can of the operation before it commences. The overview is also of value for recordkeeping purposes for those who may wish to plan similar operations and need to reference previous programs to gain experience from previous operations.

Well and Reservoir Data

The drilling department and the subsurface team provides well and reservoir data. The data included is that most often referenced by contractors for planning, pressure, temperature, depth, fluid type, and weight and underbalance information.

This data is used to calculate many of the operating parameters, including the operating pressures for test tools and TCP firing heads, and to determine fluid displacement volumes for underbalance. Inaccurate information can have severe consequences. For example, the downhole temperature is an input to calculating the thermal expansion of the test string and some aspects of the TCP firing head calculation.

Well Test Objectives

The well test objectives are the principal reason for conducting the test. The objectives influence many aspects of the design and are therefore an important reference in the program. The well test objectives should be listed

in the Well Test Program as stated by the subsurface team, using the same wording.

Achieving the test objectives is the principal measure of success of the test. Including this reference may be particularly useful if, during the course of executing the program, the procedure for a specific task needs to change as a result of unforeseen problems. Understanding the test objectives is important to developing an appropriate contingency procedure.

Well Status Assumptions

The well test operation follows directly from the drilling operation, which is governed by the drilling program, in order to ensure continuity of the operation as it changes from drilling to testing. The test program includes certain assumptions as to the well status at the point where the test program commences. They are not simply arbitrary assumptions; the test program is a controlled document approved by management in the drilling department. The assumptions communicate to those drilling the well the specific well conditions for which the well test is designed and which must be in place for the start of the well test program.

Well status assumptions typically include

- BOP ram configuration and pressure test
- Casing and liner data, including size, weight, setting depths, and final test pressure
- Wear bushing size and status
- Casing scraper across the packer setting depths
- Logging operations completed
- Well fluid type weight and condition
- Radioactive pip tags located as required in liner/casing

Roles and Responsibilities

Well test activity introduces many new contractors to the facility and also requires support from facility personnel. Because facility-based personnel roles and responsibilities during a well test often differ from the drilling phase, these changed roles and responsibilities must be defined for the well test. This promotes a fuller understanding for individuals as to their duties in relation to this nonroutine operation and can help prevent communication problems.

A flowchart may also be included to provide an overview of the reporting structure during this nonstandard phase of operations (refer to Figure 1.2 in Chapter 1). A reporting flowchart is a useful reference when test data starts to become available. Unless the reporting structure is clearly defined, the well test engineer may find him- or herself corresponding to a myriad of customers — subsurface engineers, drilling managers, asset managers—at a time when the well test engineer's attention should be firmly focused on the activity of

the well test. Another danger associated with loose lines of communication is the distribution of field data, which may yet be subject to validation.

A typical set of well test specific roles and responsibilities is provided in the appendices.

Preparations

Incorrect or incomplete equipment preparation may result in costly operational failures and delays. For example, inserting an incorrect rupture disc into a downhole tool may result in the inability to operate that tool from surface or in the premature activation of the tool, necessitating a costly retrieval of the test string.

A checklist of preparations for each well test service is provided in the program to identify well-specific preparations not addressed in contractor standard operating procedures.

During the design phase, many of the equipment configuration and operating settings specific to each service are decided from planning meetings and calculations. The personnel who set up and operate that equipment on the facility are not always the same ones involved in the design work. It is therefore important to provide this information for reference in the program. Overall control of this process lies with the well test engineer, who will witness the key equipment preparations.

Following are some examples of the service-specific preparations typically included in the program;

Generic preparations common to all services

- Inventory checks made for all equipment
- Equipment inspected for transportation damage
- Shortfalls and damages reported to the well test engineer
- Hazardous activities such as pressure testing, working at heights, electrical work, and dangerous goods performed in accordance with the facility safety management system

TCP Preparations

- Confirm with measurements of the loaded guns that the correct perforating interval has been selected (*Note*: it is not unusual for the perforation interval to be finalized at the well site, after the final logs have been run and long after the program has been issued. A well test is an exploration activity with many uncertainties. The program may simply state that the perforation intervals will be confirmed by the subsurface team after the final logs have been run.)
- Witness firing head settings and calculations and confirm that the inputs (e.g., fluid weights, pressures, and temperatures)
- Prepare subassembly drawings showing dimensions and TCP firing head settings.

DST Preparations

- Review all tool settings and operating calculations; confirm the correct inputs have been used.
- Pressure-test tools and assemblies on deck as per contractor test procedures to the general test pressure; record all tests on a chart.
- Have well test engineer witness the installation of rupture discs and shear pins.
- Review string movement calculations to ensure correct packer weight or packer seal bore spaceout.
- Prepare subassembly drawings with dimensions and tool settings.

Tubing Preparations

- Lay out, clean, and inspect tubing and pup joint end connections, drift all tubulars.
- Strap (measure) each joint, use overall length dimensions only (made-up lengths will be subtracted in the tally), paint length and joint number on each.
- Prepare a tubing tally with all tubing lengths and identification numbers

Subsea Preparations

- Prepare an assembly drawing showing the spaceout of the subsea test tree inside the BOP. Include all relevant dimensions.
- Function and pressure-test the subsea test tree and lubricator valves on deck.

Surface Equipment Preparations

- Lay out and assemble surface equipment in accordance with the layout and P & ID drawings.
- Confirm that relief valves and automatic shutdown switches are located according to the P & ID and that the settings and calibrations are correct.
- Pressure-test the surface equipment in accordance with the pressure test procedure. (This procedure is sometimes prepared by the well test engineer and included in the program. But it is not unusual for the well test service contractor supervisor to prepare this procedure for review and approval by the well test engineer at the well site.)
- Function-test the boiler, compressors, and burner head ignition system.
- Complete surface equipment checklist. (Because of the extent of the preparations required, the preparations for this service are often included in a separate checklist in the appendices.)

Data Acquisition Preparations

- Confirm type and number of gauges supplied is as per program.
- Confirm gauge calibrations are current.
- Confirm gauges are function- and pressure-tested on deck.
- Confirm gauges are programmed and set up as per the reservoir engineer's requirements, either specified in the program or via direct instructions.
- Confirm a new battery is installed in each gauge and that each battery has been checked.

Preassemblies

A subassembly is a number of individual tools connected together to form a single lift that can be handled and installed as a unit. This saves much time by reducing the number of lifts to the drill floor.

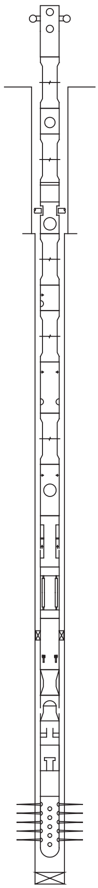
On deck these items are connected using hand tools. During installation, they require additional torque, which is applied using drill floor tong equipment. This is a time-consuming exercise inasmuch as any individual tool might require the servicing of several connections. With the increasing cost of offshore facilities, it is becoming common to make up some of the subassemblies prior to mobilization so that less critical path time is spent servicing tools as they are installed in the test string. This is not a universal practice yet, and there may be certain subassemblies that cannot be serviced onshore owing to their size or lack of facilities. A typical list of subassemblies required for a test string might includes the following.

- TCP guns
- TCP firing head
- Packer
- Gauge carrier, tester valve
- Circulating valve
- Subsea test tree
- Lubricator valve
- Flowhead

Every subassembly must be measured, or strapped, prior to installation. Since the length of each must be entered into the running tally, these measurements must be witnessed by the well test engineer, who is responsible for accuracy of the tally.

The subassembly preparation must include reference to any contractor-specific procedures for tool preparation. Every tool must be pressure-tested and any tool settings witnessed by the well test engineer, along with calculations in support of rupture disc, shear pin, or nitrogen charge settings.

Well Test String Diagram



Description	ID (in)	OD (in)	Length m	Depth (m)
Flowhead	3.0	N/A	3.5	
Tubing	3.5	4.5	38.0	–6.8
Lubricator Valve	3.0	8.0	1.8	31.2
Tubing	3.5	4.5	356.3	33
Subsea Test Tree	3.0	16.0	6.0	389.3
Tubing	3.5	4.5	2000.0	395.3
Secondary Circulating Valve	2.25	5.0	0.8	2395.3
Tubing	3.5	4.5	30.0	2396.1
Reclosable Circulating Valve	2.25	5.0	2.5	2426.1
Tubing	3.5	4.5	30.0	2428.6
Test Valve	2.25	5.0	6.0	2458.6
Hydrostatic Reference Tool	2.25	5.0	2.8	2464.6
Gauge Carrier	2.25	5.5	2.5	2467.4
Packer	2.25	9.63	2.2	2469.9
Crossover	2.25	5.0	0.6	2472.1
Debris Sub	2.25	5.0	1.0	2472.7
Release Tool	N/A	4.5	1.8	2473.7
Firing Head	N/A	4.5	1.5	2475.5
Safety Spacer	N/A	4.5	3.0	2477
TCP Guns	N/A	4.5	20.0	2480
Bottom bullnose				2500

FIGURE 7.3 Test string diagram

Contractors must also provide subassembly drawings showing all the critical dimensions. Such drawings are useful when describing the subassembly installation procedure and in the event a tool parts downhole and fishing equipment is required.

Making up Preassemblies

On a floating facility the subsea test tree and flowhead subassemblies cannot generally be made up at the time of their installation in the test string. This is because of the size and shape of these assemblies. In the case of the subsea test tree, the large diameter of the components renders them difficult to access using tong equipment, combined with the weight of the test string tailpipe.

At this point it is required that this assembly be serviced without any tailpipe in the rotary.

The flowhead is installed high in the derrick on a floating facility. This height can be anywhere from 5 to 10 m when fully landed and 12 to 17 m during installation — hardly accessible to the makeup tools.

A Well Test Program written for a floating facility generally includes a procedure to pick up and service these two subassemblies prior to installation of the test string and on critical path.

Test String Installation

Installation of the test string requires a good deal of coordination between the rig crew and various well test contractors because it entails the installation of perforating guns, the packer, test tools, tubulars, subsea equipment, upper tubing string, the flowhead, and possibly pressure control equipment. The process of installing the test string in reality involves several tasks, some of which entail complex procedures individually. For this reason, the test string installation is often divided into subsections according to service (i.e., TCP, DST, tubing, subsea, and flowhead), or grouped together into operations that are carried out collectively. For example:

- Bottomhole Assembly; comprising the TCP guns, DST tools, and packer, which are normally made up and pressure-tested together.
- Tubing Running and Spaceout Procedure, a procedure taking 12 to 18 hours, depending on the well depth. The spaceout of the test string may be included with the tubing procedure if the spaceout is achieved using the tubing to tag a packer or fixed point in the well. If not, a wireline correlation procedure may be required as a separate section.
- Subsea Test Tree, Landing String, and Flowhead Installation.
- Pressure Control Equipment (if required).
- Given the above, tasks may involve crews working together for the first time. The activity toolbox meetings for each section are particularly important in order to establish awareness of the hazards, responsibilities, lines of communication, and agreement on the detailed procedure for carrying out each task. Many of the deck crews and floor hands will not have read the procedure, instead relying entirely on toolbox meetings and directions from supervisors to carry out the various activities in the procedure.

In support of the individual tasks within this operation the program includes various references.

Bottomhole Assembly — References

- Running Tally.
- Test String Diagram.

- Compensator Use Managed by Driller, relevant only to floating facilities. The compensators help to reduce the effects of rig motion on the test string when landed in the well or when there is potential for the test string to hang up at a restriction. The procedure should highlight the requirement to use the compensators whenever there is a potential for the test string to hang up inside the well — for example, when the packer is passing through the BOP and the wellhead.
- Contractor Assembly Drawings.
- Contractor Standard Operating Procedures, provided in the appendix to the program or in separate contractor manuals. Examples include explosives handling, test tools, and packer handling procedures.

Tubing Installation and Spaceout References

- Running Tally.
- Test String Diagram.
- Tubing Handling Procedures.
- Packer Running Procedures - The packer is the largest diameter tool in the lower test string and most likely to hang up or contact an obstruction. The small clearance between the packer and the casing results in a high fluid velocity over the surface of the packer seals. The contractor supplying the packer will provide procedures that include maximum running speeds to avoid washout of the seals.
- Well Control Procedures

  Monitoring the trip tank so as to determine whether the well is taking fluid or whether returns from the well exceed those expected by normal metal displacement of the test string.

  Well Control Crossovers, required as a contingency in the event the well takes a kick when running the tubing. A well control crossover is attached to the top of the tubing to allow a standard well control valve to be fitted to help control the kick.
- General Housekeeping

  Maintaining covers over open pipe and keeping loose tools and fittings away from the rotary table.

Subsea Test Tree, Landing String, and Flowhead References

- Running Tally.
- Test String Diagram.
- Subsea Subassembly Drawings.
- Subsea Contractor Standard Operating Procedures: includes detail on tool preparations, umbilical handling, and clamp installation.
- Tubing Handling Procedures.
- Flowhead Handling and Installation Procedure.

Commissioning

Commissioning a test string is the process whereby a fit for purpose installation is established following specific tool setting procedures and pressure tests to confirm seal integrity. This process varies according to the type of packer and test tools and typically includes the following

1. Test String Pressure Test
2. Spaceout
3. Land off
4. Packer Set
5. Tool Activation

TEST STRING PRESSURE TEST

In order to establish the integrity of the test string, every connection that has the potential to experience pressure during production must be pressure-tested to the general test pressure. Pressure tests performed on the test string during installation are as follows

1. BHA
2. Periodically during the tubing installation
3. Prior to installation of the subsea test tree assembly
4. Prior to installation of the flowhead
5. After installation of the flowhead

Tests 1 and 5 are the minimum. The pressure test on the BHA tests not only the interconnections between the tools, but also the various service connections, ports, rupture discs, and sleeves. The test on the test string after the flowhead installation establishes the integrity of the entire test string. With regard to intermediate pressure tests, resource companies often consider premium connections sufficiently reliable that intermediate pressure tests are unnecessary. The decision to perform tests 2, 3, and 4 depends largely on the condition of the equipment and the resource company's practices and experience.

SPACEOUT AND LAND OFF

The spaceout of the test string is the process of placing critical test string components at their correct depth. The critical components are the TCP guns, packer, subsea test tree, and flowhead.

In essence, to achieve a spaceout, the length of every item in the test string is tallied and entered onto a spreadsheet. Tubing is inserted between the different components to position each one at the required depth. The tally can be prepared in a number of ways, a common method being to use the wellhead wear bushing as a datum. The wear bushing acts as a no-go to a hanger fitted to the subsea tree: when this hanger lands in the wear bushing, the test string can go no further.

The subsea test tree itself includes two critical measurements: the distance to the hanger, which lands in the well head wear bushing; and the distance to the slick joint, where the BOP pipe rams will close to form an annulus seal at the wellhead.

Every item in the test string below the hang-off point in the wear bushing is measured beforehand and tallied or added up to equal the measured depth of the well so as to place the TCP guns and the packer where required. Every item above this point is also measured to place the flowhead an adequate distance above the drill floor. That is, in the case of a floating facility, the stick up must accommodate relative movement between the rig and the test string, which is fixed at the seabed.

Errors frequently occur in the tally, and so an additional spaceout check and final adjustment are highly recommended. This check can be achieved in a number of ways, often depending on the type of packer used.

SPACEOUT AND LAND OFF WITH A PERMANENT SEAL BORE PACKER

Prior to running the test string, the outer packer body and seal bore are set on wireline. The wireline incorporates a gamma ray sensor and casing collar locator; these devices provide a precise means of determining the packer depth in relation to the casing and the formation.

After setting the packer body, a set of seals, together with a locator designed to land inside the packer body, is fitted to the lower part of the test string. TCP guns are suspended below the locator.

The remainder of the test string tools and tubing are installed, gradually progressing toward the bottom.

As the locator nears the packer body, the rig compensators are engaged to ensure that no damage occurs as a result of the relative movement of a floating facility and the test string as it lands off inside the packer body. At this point, both the driller and the well test engineer carefully observe the movement of the string and the weight indicator. An approximate land-off point should be available based on the tally. Once this is confirmed by a loss of weight on the indicator, the well test engineer has an increased level of confidence that the locator has landed in the correct position. Additional weight is applied to confirm that the string has been fully located.

If the BOP rams are closed at this point, they will mark the pipe at the subsea level. This length of pipe is normally painted white before installation to provide a better indication of the ram marks. The rams are opened again, and the painted joint is retrieved to surface. A measurement of the ram marks to a tubing joint connection below that mark provides a spaceout reference at the seabed. With the painted joint removed, the subsea test tree is installed, and its position is adjusted with short pup joints in order to place the slick joint at the same depth determined for the ram marks. The test string is

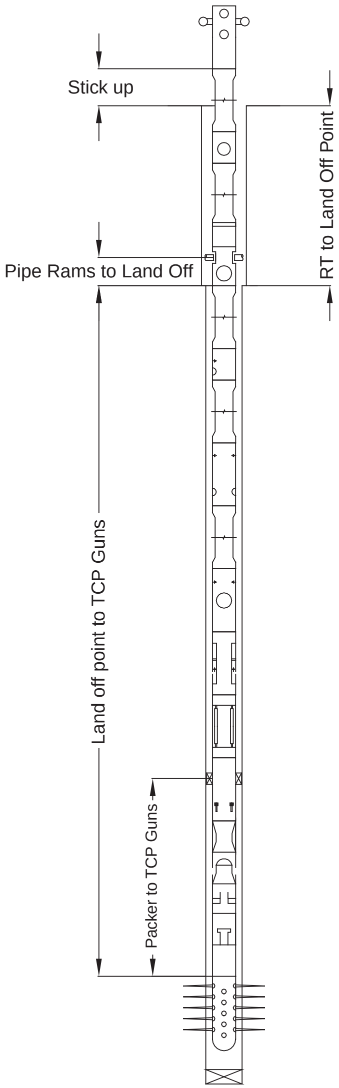


FIGURE 7.4 Spaceout dimensions

then run with the subsea test tree, the flowhead is installed, and after pressure testing, the test string is landed out so that the packer locator is inside the packer body and the subsea test tree is landed in the wellhead and the slick joint, opposite the BOP rams.

LAND OFF WITH A RETRIEVABLE PACKER

A retrievable packer requires both string movement up and down and rotation to set. Because retrievable packers are used, the land off and spaceout are complicated by the presence of telescopic slip joints in the well. Upward movement

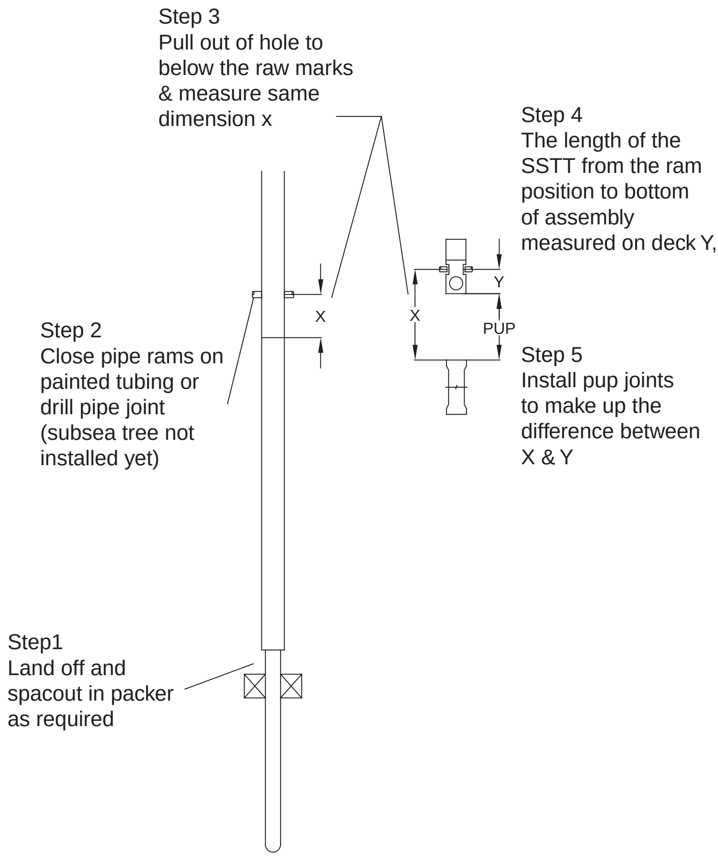


FIGURE 7.5 Spaceout with seal bore packer

and rotation of the test string are necessary to activate the packer slips. Subsequent downward movement places the packer in compression and completes the setting process. The downward movement must be calculated to close the telescopic slips the required amount and to land the test string at the wellhead. Weight loss will be observed as soon as the packer slips engage and take the string weight below the slip joints. Additional weight loss will be observed when the test string lands in the wellhead.

These operations are typical of their type; however, procedures do vary according to the make and type of packer. In every case, the well test engineer reviews these operations in consultation with the contractor supplying the packer.

FLOWHEAD INSTALLATION

The flowhead merits particular discussion in relation to floating offshore operations. As previously discussed, the flowhead must be elevated above the level of the drill floor, in order to accommodate movement of the facility

due to the metocean conditions of tide and heave. At the time of its installation, the test string has not yet been tested, nor has it been landed. Consider that when the flowhead is attached to the test string, the test string is set in the rotary slips and moves up and down with the motion of the facility, At this point, the compensators are not yet engaged. Care must therefore be taken that no point in the test string will contact and hang up on a restriction or shoulder, in particular the packer or the wellhead. In order to ensure this does not happen, the flowhead is installed as an assembly with a tubing joint already attached to it. This ensures that the packer and the subsea tree are still a full tubing joint above their respective landout points. The flowhead is an awkward lift and requires careful handling during installation; this operation must be preceded by a detailed toolbox talk.

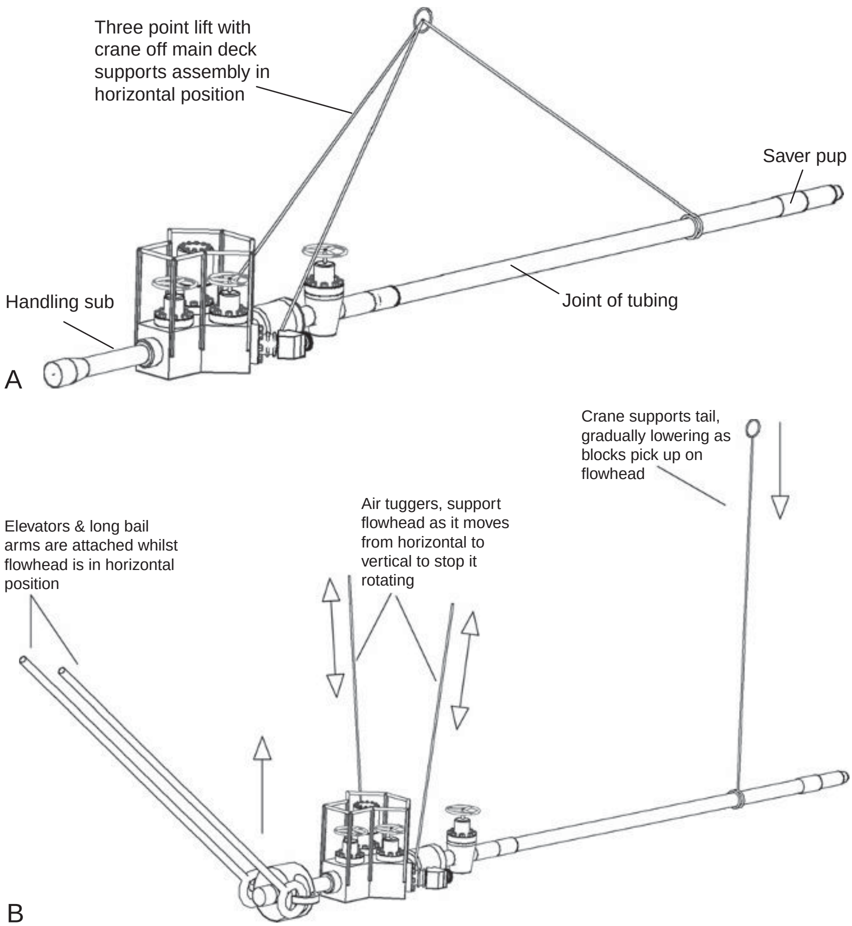


FIGURE 7.6 (a) Flowhead handling (b) Flowhead handling

TOOL ACTIVATION

The various tools placed in the test string are generally installed in a run mode. In other words, the tools are in a configuration best suited to permit the installation of the test string. The tester valve, for example, is a ball valve designed to operate as a normally closed valve. This is inconvenient during installation since the test string must fill with well fluid. The tester valve normally has an installation setting that locks it into the open position and is placed in the operating position following an activation procedure.

A typical sequence for setting the various tools from run to test mode is as follows;

Conduct low-pressure test on the annulus to verify that the packer is set and the BOP rams are sealing on the subsea slick joint.

Increase the annulus pressure to lock open the tubing fill test valve and to activate the hydrostatic reference tool. This pressure will also be observed inside the tubing through communication ports on the tubing fill test valve. These ports close during this operation.

Further increase annulus pressure to activate the downhole tester valve, No further increase in tubing pressure should be observed, thus confirming the tubing fill test valve has activated.

Bleed off the annulus pressure and the well test valve will close.

Bleed off any remaining tubing pressure at this point.

Establishing an Underbalance

A final task prior to firing the TCP guns is the introduction of the underbalance so that the reservoir fluids can flow to surface. Diesel is a common underbalance fluid and is readily available on most facilities in the quantities desired. Resources needed for this operation include the rig cementing services unit and a supply of diesel from the motor room. Because this operation involves interfaces between several of the services on the facility and the well test crew, the procedure should address the interface issues, which include;

- The rig safety management system or permit to work system
- Communication and overall responsibility for the transfer operation
- Other controls and measures to manage the operation including
- Pressure testing of lines and valves critical to the operation
- Methods for monitoring volumes pumped and volumes returned
- Storage of fluid returns, including the use of the trip tank and pits
- Pressures indicating underbalance and U-tube pressure
- Contingency procedures in the event of valve closure, leak, or seal failure

Before the operation commences, the well test engineer will perform a calculation to determine the volume of diesel required to achieve the desired

underbalance pressure, leaving an adequate safety margin to ensure diesel is not accidentally displaced through the circulating valve and into the annulus.

To displace the fluid in the test string with underbalance fluid, a valve providing tubing to annulus communication near the bottom of the test string is opened. Depending on the valve design, this is usually achieved with tubing pressure cycles. As a preliminary step, a volume of water is pumped to the test string prior to the diesel to ensure the correct valve lineup; returns taken from the annulus to the trip tank provide the necessary indication. Once the correct valve configuration has been confirmed with fluid returns to the trip tank, the diesel supply is direct to the pump and displaced to the test string, pushing the heavier kill weight fluid into the annulus. The returned fluid is recovered back to the facility trip tank, and the volumes are monitored to ensure the desired displacement is achieved. During the displacement, the well test engineer will direct the cement unit operator not to exceed preset limits for pump rate and pressure. This ensures no other valves downhole are operated accidentally. The downhole circulating valve is then closed in preparation for the test. The procedure will include all the steps necessary to operate the valve as per the contractor's procedures.

The above procedure assumed diesel as the underbalance fluid, but other fluids including water, base oil, and nitrogen gas essentially involve the same downhole valve manipulations.

PRETEST SAFETY MEETING

Just prior to perforating TCP guns and opening the well to production, a thorough pretest safety meeting must be held to ensure that all safety controls are in place and personnel are aware of operations and their responsibilities.

This safety meeting is attended by all parties connected with the well test, including facility management, resource company representatives, the driller and floor hands, service contractors, and deck crew. Typically, the meeting takes place on the drill floor and takes 20 to 30 minutes to ensure thoroughness. The meeting is normally facilitated by the well test engineer using a checklist of well test safety-related items to ensure all points are covered. The checklist includes a sign-off upon completion.

The topics covered by the checklist include

- Permit to work for well test operations
- Responsible personnel and communication focal points
- Review of sequence of operations, expected flowing conditions, and durations
- Review of operation of emergency shutdown system, who is authorized to operate it, and under what circumstances
- Emergency response during a well test

- Review of metocean conditions, wind direction, and sea state
- Final check and confirmation of equipment readiness and valve alignment

An example pretest safety checklist, provided in the appendices.

Perforating

This section of the program details the short but important task of detonating the perforating guns. References for this task include the perforating contractor procedures and the TCP firing head calculations performed by the TCP specialist and reviewed by the well test engineer during deck preparations. The accuracy of firing head calculations is dependent on the accuracy of the data supplied — for example, the fluid weight above the firing head and the accuracy of the depth to the firing head. Often this data is available only after the program is written and only just prior to running the test string.

This procedure varies considerably according to the firing head system. There are generally two types of systems: pressure activated or drop bar. The firing head also normally incorporates a time-delay mechanism. Regardless of the type of system, some preliminary steps must be taken to ensure a successful operation.

- Verify that all valves are open to the firing head, including the tester valve, subsea valves, and the required valves on the flowhead.
- Ensure that the pressures in the tubing are closely monitored to identify any indication that the guns have fired.
- Confirm computer pressure and temperature acquisition systems are acquiring prior to the commencement of this task with data sampling rates set to a high frequency, (e.g., every second).

For a pressure-activated firing head, the pressure must be applied above the underbalance fluid. Note that the underbalance fluid is a lighter fluid; therefore, the reduced hydrostatic pressure of the underbalance fluid should be taken into account when calculating the activation pressure. This pressure is applied using the cement unit, which can generally provide a more accurate measurement of volumes and pressures than the rig mud pumps. In the case of a nitrogen underbalance fluid, the pressure may be applied using the nitrogen unit. The activation pressure is generally held for only a short period of 1 to 2 minutes, depending on the firing head design. After the activation pressure has been held for the required period, it is common practice not to completely bleed this pressure to zero but to maintain a slight positive pressure on the test string. This is in order to provide a more positive indication that the guns have fired. When guns detonate, the indication received at surface is often slight —

sometimes only a dull thud and a rattling of the tubing string, followed by a sudden increase in pressure as the reservoir fluid produces into the test string. However, this positive indication does not always occur. Without seeing an increase of pressure, there can be significant uncertainty. It may be that the guns have fired and the well is not producing, or it may be that the guns have not fired at all.

TCP CONTINGENCIES

TCP systems are generally very reliable, provided all of the pre-job checks have been completed as per the contractor's procedures and data regarding fluid weight pressures and temperatures are accurate. However, reasons other than an inherent failure in the gun system might give rise to problems. Examples include a closed valve in the system or debris settling near the bottom of the test string, creating a communication barrier between the firing head and surface. More commonly, a TCP system might work, but little or no indication is observed at surface, giving rise to doubts that the guns have fired.

Contingency procedures describe a troubleshooting process to verify the firing head calculations and the valve lineup. The delay period is normally extended before the firing procedure is repeated, often at elevated pressures in the case of a hydraulic firing head. Should the volumes pumped to achieve the firing pressure suggest that a downhole valve is closed, contingency procedures will direct the use of slickline equipment to drift to the firing head to verify that there is a free communication path.

Cleanup and Flow Periods

A flow or production period is any period during which reservoir fluids produce into the wellbore. This process is also known as a drawdown for the reason that the pressure at the reservoir face and in the immediate wellbore area drops from its initial shut-in value to some lower value during a flow period, the magnitude of the drop depending on production rate and certain formation and fluid characteristics.

During the various flow periods, the well test engineer is very much an observer of the activity of the well test crew. His or her role is largely one of quality control, checking to see that the conduct of the well test is in line with the procedures detailed in the program and to ensure adherence to safety controls.

INITIAL FLOW

Programs generally include a short initial flow period of about 10 minutes followed by a shut-in period of about 30 to 60 minutes to precede the cleanup flow. The purpose of this short initial flow is to clean the perforation tunnels of debris and obtain initial reservoir pressure.

CLEANUP

Conditions are most unpredictable during the cleanup and initial part of the main production period until conditions stabilize. During the cleanup, changes to the adjustable choke must be made in response to buildup of pressure and the fluids returned at surface. Initially, returns are taken to the storage tank. As pressure continues to increase, the production is switched directly to the flare. In cases where the wellhead pressure is naturally low, the entire fluid production for the period might be taken to the tank and later pumped to the flare for disposal.

In addition to process equipment adjustments, well-site personnel require guidance as to what defines a cleanup. This can be difficult to determine, and the decision can have significant consequences in relation to cost and data quality. On one hand, extending the production period to achieve a thorough cleanup will significantly add to the cost of the test and might only add a negligible incremental improvement to the quality of the cleanup. On the other hand, terminating the cleanup too early might result in contamination of the separator and fluid samples later during the main flow.

Toward the end of the cleanup, some programs call for a short period of production with the separator in order to take a set of contingency samples and to provide an early indication of the production rate. This data is useful later for deciding what choke sizes to select for the main flow period.

Options available to the resource company to manage these uncertainties include providing guidance in the program and sending a subsurface representative to the well site to assess the well conditions and recommend appropriate responses.

A typical cleanup procedure might read as follows

1. Wait for pressure response to indicate TCP guns have fired.
2. Open well at choke manifold on small adjustable choke to storage tank.
   a. Record volumes of underbalance fluid recovered in storage tank.
3. Increase choke gradually under the direction of the well test engineer.
4. Direct flow to the flare when adequate wellhead pressure is available to sustain a good burn
   a. Continue monitoring fluids at surface and record the change from underbalance to drilling fluid and reservoir fluid.
5. Continue increasing adjustable choke under the direction of the well test engineer to achieve the maximum flow rate allowed for the system
   a. Make adjustments to the choke to optimize burn efficiency or if heat radiation is excessive.
   b. Monitor fluid returns at all times taking fluid samples for BSW and gravity measurements.
6. Cleanup will continue until the following criteria have been met.
   a. BSW <1 percent over three successive 15-minute readings.

   b. Water production, if any, must be monitored; chloride levels in samples will indicate if water is drilling fluid residue or formation.
   c. Wellhead pressure stable less than 10 psi variation over a 10-minute period.
   d. Wellhead temperature stable less than 2 Celsius variation over a 10-minute period.
7. Confirm with the drilling supervisor and with head office that the criteria have been satisfied to obtain approval to shut-in.
8. Shut-in downhole; once a pressure drop of ~5 percent has been observed at surface, shut-in at the choke manifold.

Shut-In Period

A shut-in period following the cleanup is required to allow time for the reservoir pressure to build to its maximum value. The wellbore from the reservoir to the surface equipment is filled entirely with reservoir fluid, all drilling and underbalance fluid having been removed during the cleanup. Downhole gauges sensing pressure below the tester valve record this buildup data, which can be utilized later by the subsurface team to assist with modeling. The duration of this period will vary according to the expected nature of the reservoir formation. Typically, this period will last 1.5 times the cleanup flow.

A typical buildup procedure will include the following guidance.

1. The duration of the shut-in period will be 1.5 times the cleanup flow period, or as directed by the on-site subsurface engineer.
   a. During the shut-in, no activity shall take place that might disturb gauge data, such as valve manipulation on the flowhead or choke manifold.
   b. Note that the pressure trapped between the downhole tester valve and surface will drop as a result of thermal contraction to the fluid in the test string. No action is required.

MAIN FLOW PERIOD

Depending on the well test objectives, this period might involve production at a single rate or multiple rates. This aspect of the test design is the responsibility of the subsurface team because the data derived from this activity is an important element in reservoir modeling. The program details the order and duration of each flow period and the data requirements, including samples for each.

A typical main flow period procedure might read as follows.

1. Open the downhole tester valve with annulus applied pressure.
2. When a pressure response is observed at surface, open the well on a small adjustable choke to commence production.

3. Continue to increase the adjustable choke until the production rate is estimated to be equal to the first desired flow rate.
4. Change to a fixed choke.
5. Pass production to the separator and commence readings.
6. Acquire PVT samples, samples for fluid properties, and assay and trace element measurements.
7. At the end of the first rate period, switch to an adjustable choke.
8. Increase the adjustable choke to achieve the next desired flow rate.
9. Repeat the steps above for each successive flow period.

FINAL SHUT-IN

The final shut-in period serves a similar purpose to the shut-in following the cleanup, but the final shut-in might be considered more representative since the flow periods immediately preceding it involve a longer drawdown on the reservoir. The resultant buildup data therefore provides a greater radius of investigation into the reservoir since fluids travel from further into the reservoir to replace those lost during the test.

Well Kill and Test String Retrieval

After the final buildup, the well must be secured in such a manner as to permit the safe retrieval of the test string. This is achieved by displacing the reservoir fluids in the test string with a heavy kill weight fluid to provide a barrier; the BOPs provide a second barrier. The procedure for this retrieval varies, primarily according to the test fluid, oil or gas, and also according to the type of packer and other test tools in the string.

A typical sequence showing the main procedural steps for a gas and oil well test is outlined in the following section.

WELL KILL — GAS

1. With the tester valve in the closed position, open the surface choke manifold and bleed the entire tubing contents above the tester valve to zero.
2. Lubricate the kill weight fluid to fill the test tubing above the tester valve to surface.
3. Open the tester valve.
4. Bullhead kill fluid into the test string; this will push reservoir fluids below the tester valve back into the formation
   a. Calculations for the volume between the tester valve and the formation will indicate pump volumes required.
   b. A sharp rise in pressure will occur when the kill weight fluid contacts the formation.
   c. Do not exceed formation rock fracture pressure during the bullhead process.

5. Observe the well for 10 minutes to indicate the well is dead.
6. Open pipe rams and unset the packer.
7. Circulate 1.25 times the entire well volume, taking returns to the rig pit system.
   a. Monitor continuously for gas in the returns; some gas may have been trapped below the packer.
8. At the end of the circulation, observe the well for a further 10 minutes to confirm dead.
9. Flush surface equipment with seawater.
10. Proceed to pull out of hole with the test string.

WELL KILL — OIL

1. With the tester valve in the closed position, bleed the tubing head pressure to zero to the well test equipment.
2. Cycle the reclosable reversing valve to the reverse position.
3. Pump kill weight fluid into the annulus to displace the tubing contents to the well test equipment.
4. When annulus fluid returns are observed at surface and no oil contamination is evident, stop pumping.
5. Close the reversing valve and open the tester valve.
6. Bullhead kill fluid into the test string; this will push reservoir fluids below the tester valve back into the formation.
   a. Calculations for the volume between the tester valve and the formation will indicate pump volumes required.
   b. A sharp rise in pressure will occur when the kill weight fluid contacts the formation.
   c. Do not exceed formation rock fracture pressure during the bullhead process.
7. Observe the well for 10 minutes to indicate the well is dead.
8. Open pipe rams and unset the packer.
9. Circulate 1.25 times the entire well volume, taking returns to the rig pit system.
   a. Monitor continuously for gas/oil in the returns; some gas may have been trapped below the packer.
10. At the end of the circulation, observe the well for a further 10 minutes to confirm dead.
11. Flush surface equipment with seawater.
12. Proceed to pull out of hole with the test string.

Both of the above procedures for well kill entail pumping cold fluid into the well. This may cause contraction of the test string and may also affect the operating pressure of the tester valve by cooling the nitrogen reference chamber. Close monitoring of the tester valve and surface pump pressures

must be maintained during this operation in the event the valve closes unexpectedly.

Unseating a retrievable packer typically involves picking up on the test string to open the telescopic slips and lifting the compression weight on the packer. As the packer unseats, the driller should be made aware of the potential for some gas to escape from below the packer seals. Once unset, the test string can again be lowered to a position where the BOP rams can close on the SSTT slick joint in preparation for circulation.

A permanent seal bore packer also requires upward movement to remove the seals on the packer locator from the packer seal bore. However, the test string cannot be lowered prior to the circulation because this would re engage the locater seals inside the packer, closing the circulation path. The driller should also be made aware of the correct height to pick up to allow BOP pipe rams to close on the pipe below the SSTT, if required for any well control issues that may arise during the circulation.

Retrieving the Test String

Before disconnecting the flowhead, the surface well test equipment should be flushed in preparation for dismantling. Flushing the surface equipment can be achieved easily by closing the master valve on the flowhead and pumping seawater, followed by inhibited drill water through the equipment on deck. This operation normally takes about 15 to 30 minutes to ensure that all equipment, pipework, and the like have been thoroughly flushed. Once completed, the lines may be disconnected from the flowhead, and the task of retrieving the test string can begin.

Precautions during the test string retrieval operation should be taken against swabbing the well. This can happen particularly on gas wells, for the packer can act like a piston. The fluid bypass area around the outside of the packer is not great, so as the test string travels upward a suction force is generated below the packer, which can induce an underbalance and cause the well to flow. The driller must be alert to this hazard and monitor well fluid volumes at the trip tank to ensure there are no gains at surface. The upward speed of the packer will be limited to minimize the effect, particularly while the packer is inside a liner.

As the test string is being retrieved, other rental equipment on deck may be decommissioned, again observing good housekeeping precautions.

The well test engineer will busy him- or herself assisting in the management of logistics. Rental equipment should be packaged safely for transportation and shipping manifests, packing lists, and associated documentation prepared as required.

After the downhole gauges have been retrieved at surface, the gauge data is analyzed and validated for quality control purposes. This task is ideally performed by the subsurface representative.

Contractors submit reports to the well test engineer as required by their service contract. In particular, well test production, gauge, and sample data must be carefully backed up and a complete copy provided to the well test engineer.

End of Program

Retrieval of the test string marks the end of the Well Test Program. The next critical path operation, that of abandoning or isolating the well, is managed under the drilling program. However, it is sometimes necessary to pick up the well test preassemblies, such as the subsea test tree and the flowhead in order to break service connections.

DEMOBILIZATION

The well test engineer's focus after completion of the well test program is the logistics associated with the demobilization of equipment and personnel. Contractually, the resource company pays charges until both equipment and personnel return to an agreed point of origin. Before this can happen, all contractors must pack away their equipment and issue manifests, field reports, and service tickets to the well test engineer.

SERVICE TICKETS

A service ticket is a well-site record summarizing the most relevant details for each service provided. This record is prepared by each senior contractor supervisor and reviewed and signed by the well test engineer at the well site. On the basis of the information provided in the service ticket, the contractor subsequently submits an invoice for the service to the resource company.

WELL-SITE REPORTS

An end of well report is a detailed record of the service provided by a contractor. This record provides a useful reference to assess the quality of the data recorded during a well test. In particular, it addresses anomalies or incomplete data. Referencing the report identifies events that may have influenced the quality of the data — for example, adjustments to a separator or choke manifold. It is also referenced for incident investigation purposes, particularly in relation to equipment damage and production interruptions that might also have influenced data quality. The report also provides support for contracts and invoicing purposes.

Every well test service contractor must submit a report to the well test engineer. The content varies significantly according to the nature of the service. For instance, a contractor providing a rig cooling service might only submit events, heat monitoring data, and well-site personnel records, whereas the surface well test contractor will have a more comprehensive

report to submit. Typically, a comprehensive end of well report includes the following:

- Sequence of events
- Pressure test records
- Calibration records
- As-installed assembly drawings
- As-installed equipment layout drawings
- Tallies
- Well test data (downhole gauge pressure and temperature data and surface production data).
- Sample records
- Well-site crew list
- Incident reports
- Service tickets

It is common practice to issue a field version of the report to the well test engineer at the well site and a finalized version after demobilization, the final report being subject to review by the well test engineer. Together all of the contractor reports provide a detailed record for every aspect of the well test. Acceptance of the final report is often a contract condition for payment of invoices. In addition to the uses identified above, these reports also provide input to the continuous improvement process, whereby the participants learn from their successes and mistakes and develop practices and procedures to improve the quality of subsequent operations.

Chapter | eight

Continuous Improvement

CHAPTER CONTENTS

"Without standards, we have no logical basis for decisions or actions."

—Joseph Juran[1]

Standards have always existed, but they often fall into disuse or irrelevance. Throughout this book we have made frequent reference to the relationship between well test planning and adherence to standards in the form of regulations, best practices, engineering design specifications, and company processes. *Continuous Improvement* ensures that those standards used in connection with well testing remain both useful and relevant. This process also ensures consistency by helping to unify communications and operations through all functions in the company.

Continuous Improvement does not improve processes and products directly; rather, it improves the logical basis, the standard used in making and controlling them. Modern industry uses standards to manage complexity to survive in a dynamic marketplace. Without their logical structure, management and operators would have only subjective means for trying to achieve satisfactory outcomes. Continuous Improvement keeps standards objective. In short, it is a process for the maintenance of standards.

Choosing standards unwisely leads to over engineering or under engineering, and wasting money. Too many standards lead to overly prescriptive procedures and obstruct clear thinking at the functional levels, as well as building in features that remain unused and produce too little return. Too few standards lead to subjective decision making and inaccurate procedures, and result in increased operational risk levels.

Continuous Improvement is not the same as *Quality Improvement*. Quality Improvement aims to restore or improve a company's quality standards by a once-off, organized effort. Continuous Improvement focuses on all standards regardless and involves not just a single company, but a broad collective comprising industry and other organizations. In addition, it can occur on a project-by-project basis or over many years, for it often takes a standards-making body that long to prove a new or revised standard. Finally, it usually makes changes in an existing quality structure without disturbing it unduly.

Continuous Improvement is also not a compliance process. Compliance centers on the leadership's involvement with Quality Standards, and lower management taking quality seriously, empowering employees to contribute to setting company goals. Compliance relates to consistency in leadership and, nowadays, gives outsiders a voice in company affairs by imposing legal obligations that it must fulfill in order to do business. Continuous Improvement does not create or improve company disposition to comply with laws

[1] Managerial breakthrough: the classic book on improving management performance, J.M. Juran (New York: McGraw-Hill), 30th revised edition, 1995), p. 346.

or quality goals, external or internal; it just aims to improve standards using new knowledge. It does affect Compliance when it changes a standard used in Compliance, such as, the Safety Case standard. Here, the best practice used by most companies essentially takes the Vessel Safety Case and builds and adapts it for the test's Safety Case, using the new design knowledge.

Clearly, then, much occurs behind the scenes, out in the wider world. New knowledge migrates into the company through service companies, through the well test engineer, and through the company's own links with its industrial partners and competitors. In many ways, Continuous Improvement happens without the well test engineer doing anything at all!

Continuous Improvement Goals

- Consistency in standards over time
- Communicating standards throughout the organization
- Applying standards to all company practices and operations
- Maintaining standards in good repair
- Improved planning
- Reduced risk

COLLECTING LESSONS LEARNED

Resource companies consider a well test successful if all of the objectives have been met. Generally, this amounts to experiencing no safety incidents and no environmental incidents, acquiring the technical objectives of data and fluid samples as per the program, and finally, completing the operation on time and on budget.

Table 8.1 Summary Where and How Learnings are Applied

Input	Process	Output
Lessons Learned	Collate and interpret causes and develop appropriate controls	Revised standards and controls
Contractors	Captured during detailed design planning	Revised procedures and practices
Personnel	Captured in revised planning documents.	Revised procedures and practices
Regulators	Issue of new and revised regulations	Compliance and approvals process
Standards Organizations	Issue of new and revised industry standards	Revised design standards

But even with all the well test objectives successfully completed, only rarely does everything in the program go according to plan. Problems may have been encountered that required changes to some procedures, and specific tasks may have been completed faster and more effectively than on previous occasions.

Lessons learned, or learnings as they may also be called, are inputs to Continuous Improvement that occur through direct experience during both planning and operations. Lessons learned are not simply changes that are flagged for review and later implemented. Many lessons learned are implemented immediately out of necessity, and these are of a nature that demands a change in procedure in order for the program to proceed. This happens on occasions when some unforeseen sequence of operations cannot occur in the order specified in the procedure — for example, the displacement of kill weight fluid after setting the packer due to problems with the circulating valve or because some parameter, such as an equipment operating specification in the program, is incorrect. For example, a downhole tool cycling pressure may be higher or lower than that specified in the program. Whether implemented immediately out of necessity or recognized after the fact as a result of a delay, failure, or exceptional success, lessons learned must be recorded so that the benefit can be carried forward into future operations. Various tools already exist which help manage well-site operations; these also serve to record lessons learned. These tools include the following:

- Management of Change
- Lookahead
- Daily Reports
- Wellsite Operations Review Meeting
- Incident Investigation
- Follow-up Meetings

Management of Change (MOC)

When an operation deviates from a preapproved procedure, new hazards may be encountered for which adequate controls do not exist. A management of change (MOC) process provides controls that direct personnel at the well site to follow a procedure ensuring that risk assessment and management approvals are in place before proceeding with any deviation from preapproved procedures. There are generally two types of MOC: those that require full management approval, equivalent to that of the program, and those authorized by well-site management. Well-site approval is delegated in cases where the deviation from program does not entail significant risk; guidelines within the management of change procedure exist to help well-site personnel distinguish between the two.

MOC does not apply to existing contingency procedures; these will have been reviewed and approved along with other planning documentation.

In the event that operations necessitate the execution of a contingency procedure, this is generally approved after discussion with the head office. In many instances, verbal approval only is required to put a contingency procedure into effect.

If there has been a management of change, there have been lessons learned. Having a MOC process, resource companies acknowledge that procedures can change because of changing circumstances. It is also recognition that change represents risk: by attempting to undertake an activity that might be hazardous, without full consideration of new or changed hazards, the risk level for an activity increases. MOC introduces controls to ensure that adequate consideration is given to each change and that a sufficiently high level of management has been involved with the risk assessment.

The well test engineer prepares management of change documents for each deviation to any procedure in the program. Each time a task or activity is performed differently, there is a potential to learn from the change. Management of change is a control that also captures lessons learned, which will later provide input for Continuous Improvement. Each management of change results in a change to a controlled document, the program, which then becomes a historical standard for subsequent well tests.

This process shows that Continuous Improvement has a role to play in both process and procedural improvements by taking knowledge from actual operations and changing standard practice.

Lookahead

The lookahead is a detailed schedule that records actual progress against expected progress for each task in the well test operation. This document is typically a spreadsheet maintained by the well test engineer and updated each day based on operational progress. In doing so, the lookahead highlights specific tasks that have performed to expectation and those that have not. In itself it does not identify any lessons learned, but it does point to activities where lessons learned might be found. For example, if a particular task in the program takes twice the allotted time, it may be that the procedure or its supervision was inadequate and requires revision.

Daily Reports

The well test engineer reports to resource company management on a daily basis through the issue of a daily report. The daily report summarizes activities that are both critical path and offline for the previous 24-hour period and is scrutinized by management as the official record of the well test. Of particular interest is nonproductive time (NPT) or critical path time lost to unplanned activities — for example delays due to the breakdown of equipment. NPT can highlight failures in planning or supervision, especially lack of

preparation for contractor equipment. These learnings are fed back into the overall assessment of contractor service.

Well-Site Operations Review Meeting

A well-site operations review meeting is an opportunity to capture learnings after completion of the operation and prior to the demobilization of personnel. Input provided by the different contractors at such a meeting might fall outside the procedures described in the program, but may still contribute to a safer or more efficient operation. The difficulty in identifying and capturing learnings arises in part from the lack of formal controls to capture learnings for tasks that fall outside the program. The range of topics is broad and can include almost any aspect of planning or operations, such as tool settings, schedules, equipment, design factors, personnel, logistics, contracts, and planning in general. The value in this meeting lies in the fact that field personnel are present and the operation is fresh in everyone's mind. A simple brainstorming session that lists everything that went well, and, everything that didn't, is all that is required. Later, the well test engineer can expand the points summarized on the list.

Incident Investigation

Input to Continuous Improvement may come from learnings that derive from an incident investigation. Issues giving rise to an incident investigation are generally serious injury or near misses, damage to the environment, and significant unplanned cost, such as that rising from equipment failure. Incident investigation teams might include external bodies such as government regulators and technical specialists, or teams made up of resource company management, technical, and legal expertise. The nature of the incident dictates the makeup of the investigation team; the team often includes members who have been formally trained in incident investigation. Unlike a Continuous Improvement meeting, an incident investigation team focuses exclusively on just one incident and follows a formal investigation process, which typically is structured as follows.

1. Gather all the relevant facts in relation to the incident.
2. Identify contributing factors.
3. Identify root causes.
4. Make recommendations.

Although incident investigations initially take place within days of a serious incident, it may take a number of weeks to issue the recommendations that provide input to the Continuous Improvement process. Sometimes these learnings affect controls at a high level within the company organization and can influence company policy.

Follow Up Meetings

Many of the learnings accumulated during an operation require further researches by individual contractors. The explanation as to why a piece of equipment failed to perform according to specification might need reference to a remote manufacturing center for example. Resource companies schedule follow up meetings subsequent to the operation to review all of the issues and discuss the findings in relation to each. Often this is where new controls and Continuous Improvement changes are identified.

RECURRENT THEMES

This section details some recurring themes for Continuous Improvement and at the same time summarizes many of the themes presented in this book. The fact that many of these themes are recurrent is not to suggest that resource companies do not adopt learnings, although this is true in some case. Circumstances do not always permit the application of Continuous Improvement, in particular in relation to early planning. The schedule for the well test often limits the available planning time. This is a learning that many resource companies acknowledge, but is often influenced by overriding external factors, availability of facilities, joint venture partner intervention, regulatory drilling obligations, or corporate-level objectives.

EARLY PLANNING AND CONTRACTOR BUY-IN

One of the more common threads running through well test Continuous Improvement meetings is the theme of early planning, especially in relation to obtaining early contractor input.

Well testing is a contractor-intensive operation, each providing specialized services. The successful outcome of the operation is therefore directly related to the level of commitment provided by each contractor and the degree to which contractors are involved in the resource company's planning. The term *buy-in* succinctly captures this definition in everyday language.

Historically, contractor buy-in has ensured smoother procedures and less downtime on critical path. This buy-in is achieved through the contractor selection process and through contractor participation in planning. The steps required to achieve contractor buy-in are as follows:

- Allow adequate time for detailed planning, necessary to ensure long lead engineering and specialized equipment procurement.
- Establish contractor focal points and determine their suitability for the operation.
- Involve contractors in early planning during the basis for design and detailed design stage.

- Involve field contractor personnel to obtain input to procedures in the risk assessments and the TWOP.
- Involve contractors when defining roles and responsibilities, in particular detail ownership of contractor-specific duties such as preparation of tallies, assembly drawings, and test procedures, together with participation in safety management system processes, such as safety meetings, permit to work, JSA, and STOP.
- Establish the standards required for the well test.
- Agree on key performance indicators and other auditing measures, inspections, and reviews.
- Ensure that contractor distribution is included in document control.

In effect, these steps constitute a planning best practice. The payoff for this early involvement is greater attention to detail, or a more thorough design. Contractors also bring new knowledge that can be incorporated into company practices. Within the industry, best practices evolve most rapidly in regions with high levels of activity and where extreme environments exist, such as deep water or high pressure–high temperature. The demanding nature of the environment requires the most stringent adherence to standards, particularly because the consequences of failing to follow standards or to apply effective standards are significantly greater than for other operations.

Contractor companies are often large organizations that operate globally. The specialist personnel within these organizations travel frequently between operations from one location to another, working for different resource companies, and in doing so; they acquire a broad experience of the practices followed in each location. Accordingly, these specialists bring a great deal of experience to each new project with which they become involved.

Contracts Process

Many resource companies perform well tests on an infrequent basis, and for this reason, the contracts process specific to this operation is often underdeveloped. Many organizations bypass a formal contracts process and instead obtain quotations for the supply of well test services. Usually, this is because of a lack of planning resources, combined with a lack of any established contract process. To bypass any planning process is to bypass a standard. Such standards exist to protect the resource company and reduce its risk, and in this case the many and varied risks associated with contracting well test services. Many resource companies have encountered significant additional costs and reduced standards as a result of an inappropriate contracts process, which has also had consequences for the well test objectives.

Some of the recurring key learnings in relation to well test contracts that emerge during Continuous Improvement reviews are as follows

- Involve well test engineer's input early in contract preparation, particularly in relation to the scope of work and of supply of equipment and services.
- Make terms and conditions well test-specific in relation to standby and operational charges.
- Define the roles and responsibilities of each well test contractor service.
- Define resource company expectations, specifically, standards in relation to safety and the environment, invoicing, reporting, equipment supply. and personnel competency.
- Agree on key performance indicators (KPIs).
- Ensure that contracts and quotations are the subject of document control.

DESIGN PROCESS

Lessons learned relating to well test design are usually connected with the design process and less with the technical standards referenced in design documents. A recurring issue is the introduction of last minute change to the design, such as an additional test objective or a change to a well parameter. The design process is most beneficial when input is sought from contractors and reviewed thoroughly; using the controls of risk assessment, test the well on paper (TWOP) exercises, and the validation process. Late changes to the design bypass these controls and introduce risk to the operation. Tight schedules also put pressure on the planning team to omit some of these controls, which introduces further risk. Risk assessment and TWOP controls can be rendered ineffective without proper implementation; for example, risk assessments must follow recognized standards with the outcomes incorporated into the design or procedural documentation. The TWOP produces outputs that refine the well test program. The validation must be performed by an independent competent well test engineer in order to satisfy criteria of objectivity. Ideally, the validator remains strictly separate from the planning and execution roles.

HUMAN ERROR

Human error frequently emerges as an underlying cause in many operational failures. This can manifest itself in many ways, most notably in behaviors at the well site. Aware of the high cost and commitment of an entire rig crew to achieving an operational objective, personnel often experience self-imposed pressures to avoid interrupting the operation. In order to get the job done, they may, for example, hesitate or fail to operate an ESD for just a minor problem such as a small seal leak, or they may not stop an unsafe act such as an individual working at heights without a proper safety harness. Human error during planning and preparation can also manifest itself operationally:

- Lack of experience in supervisors, individuals, or the overall crew.
- Inadequate manning levels resulting in fatigue or lack of crew coverage during critical operations.
- Lack of knowledge of the operation, due to lack of supervision, incorrect or inadequate procedures, incomplete briefings, or miscommunication.
- Insufficient preparation time; crews mobilized without adequate preparation time may make mistakes because of time pressures, skipping procedural steps or fatigue.
- Unrelated factors that may have led to a lack of focus on the job at hand; for example, crews anticipating relief at the end of a shift or leaving the well site might not concentrate on the job at hand.
- Under resourced in respect of tools, equipment, or other help, for example, many contractor operations require cooperation from rig and deck crews to move equipment, connect electrical power, perform welding, and other tasks.
- Communication failure, due to crewmembers' unfamiliarity with one another or the rig. This can include language and cultural barriers. It often takes several days for a new contractor to integrate to a well site in order to understand how the rig crews and systems operate. Integration of new personnel to the wellsite is also dependent to some extent on the thoroughness of the briefings provided on arrival.

Controls used to reduce risk arising from human error have been discussed throughout this book. In summary, these controls include the contractor selection process, the training and competence levels maintained by contractors, the early involvement of contractors in planning, the level of detail in the planning documents, in particular the procedures, well-site briefings and rig management systems, and the well-site supervision of contractors, which includes input from the well test engineer.

SUBMISSION DOCUMENTS

Lessons learned in relation to submission documents that demonstrate compliance with regulations derive from some common mistakes and problems.

A challenge in preparing submission documents is to demonstrate compliance with regulations. This might seem to be a fairly obvious statement, but submissions sometimes fail, not because resource companies fail to comply with the regulations, but rather because they fail to articulate this in the documentation.

Resource companies often use existing templates to prepare submission documents. Although this is a perfectly acceptable practice, a potential flaw exists in assuming that what was accepted for one operation will also be accepted for another. In other words, resource companies can fail to make their documents site specific, in particular, risk assessment aspects of the submission.

Regulations evolve, as do technical standards; thus, resource companies, particularly when using existing templates, could well overlook new regulations and thereby risk rejection.

Regulators work to schedules, and the submission process requires set times for the proper assessment of documents. Late submissions, perhaps due to lack of planning resources, late planning changes, or a delayed decision-making process, also contribute to problems in gaining timely regulatory approval.

PLANNING PROCESSES

A physical failure at the well site such as a misfire of guns, a leak in pressure equipment, failure to set a packer, inability to cycle downhole tools, gauge failure, poor data quality, contaminated or poor samples, are the result of either human error or mechanical failure. Considering some of these examples, guns might misfire because the operator inserted an incorrect firing pin or failed to make a correct booster termination. Alternatively, the procedure might have specified an incorrect fluid parameter, with the result that the operator based the firing head calculation on incorrect data. Downhole tools might fail to cycle because the operator inserted an incorrect rupture disc; or the rupture disc might have a manufacturing flaw and fail to operate according to specification. Gauges might fail because of the operator's erroneous programming parameter; high temperature or gun shock could also be the cause.

Lessons learned often point to the lack of, or failure to implement, controls in the planning stage, pre mobilization or during preparation at the well site. These controls include contractor equipment inspections prior to mobilization and preoperational checks at the well site. These controls require that the well test engineer use his or her knowledge of the test equipment to ensure the equipment is fit for purpose. The well test engineer reviews detailed preparations for each service, for example, tool operating pressure calculations and the installation of rupture discs, including the witnessing of the rupture disc manufacturing information.

CONTINUOUS IMPROVEMENT PROCESS

The effectiveness of Continuous Improvement lies in knowing what to control as much as how to control it.

After demobilization and after each contractor has had an opportunity to investigate issues relating to their service, typically within a month after demobilization, contractors are invited to present a summary of all learnings, good and bad. They are given a wide scope to present not simply in relation to well-site operations, but also in relation to other areas of planning and execution, for example, contracts, logistics, and invoicing. The presentations not

only list learnings in relation to each service but also provide an opportunity for each contractor to present their interpretation of the causes and to make recommendations. The checklist in the following section provides a guideline using a set of prompts or questions under a set of typical Continuous Improvement headings to help structure the information for presentation.

Significant pressure may be placed on contractors to present issues relating to their own performance in the best possible light; no contractor wishes to admit that his or her service delivery was substandard. This may reflect on them financially in terms of invoicing for services they did not execute satisfactorily and in terms of damage to their reputation. Resource companies promote a no blame culture, so that contractors are encouraged to be frank and to demonstrate a willingness to improve service quality. Time permitting, resource companies might conduct individual contractor meetings in order to provide adequate focus on each service and to promote openness in regard to sensitive issues that could reflect on a contractor's reputation.

Given the potential for such meetings to identify numerous issues, some significant and some trivial, it is more practical to invite contractors to limit the number of presentation items in order to isolate the vital few. An optimum of five issues and a maximum of ten would permit each contractor to present the most important issues while allowing adequate resources of time from the assembled group to fully discuss those issues. An unrestricted number might see the meeting give only cursory attention to major issues and focus on myriad trivial data that might easily be managed by contractors separately.

The attendees at the meeting discuss underlying causes, appropriate corrective measures, and ways to see that those corrective measures are carried forward. Ultimately, it is the resource company's responsibility to make the final decision in regard to interpreting causes, since most of the risk associated with the operation is carried by the resource company. Interpretation of the underlying causes is often based on subjective engineering judgment. As an aid to interpretation, the team might refer to a prompt sheet to examine initial and underlying causes. An operational failure might occur for any number of reasons, including

- Lack of controls
- Failure to implement existing controls
- Inadequate procedure
- Inadequate supervision
- Equipment failure
- Missing equipment
- Unsuitable equipment
- Unexpected conditions

A deeper analysis is likely to suggest an inadequate standard or noncompliance with a standard. More particularly, it is the controls used to apply

standards that are frequently inadequate or inadequately supervised. For example, if a piece of equipment at the well-site fails to operate, it is often the case that the equipment has not been properly selected, serviced, or operated. This suggests a failure in the equipment selection process or in the maintenance procedure, or inadequate training or competence on the part of the personnel operating the equipment. The more people who participate in such exercises, the more it will help to filter bias in the final results. Bias belongs to observers, not observations.

A report detailing the findings of the Continuous Improvement meeting will not in itself contribute much to Continuous Improvement without some means to ensure the changes are carried forward into planning processes. Although some planning teams may be able to review some Continuous Improvement records, this largely depends on the availability and access to those records and on the planning teams resources to spend the time to do so. Many resource companies, including large ones, often have poorly established well test planning processes. This is particularly true for those who test infrequently. If this is so, the conclusions of the meeting have little value other than to those that are likely to be involved with subsequent operations. This is one of the reasons the experience of the planning team is crucial in planning. Where good planning processes do exist, the conclusions are input to these processes using document controls to revise company standards and practices, checklists, plans, and so on.

To summarize this discussion continuous improvement manifests itself as follows

- Procedures are revised based on management of change documentation.
- Engineering and design specifications are revised with new and revised industry standards.
- State regulations are revised and changed by the regulator.
- The Safety Case is also revised using input from risk assessments performed for every operation.
- Processes are revised when new technologies either remove the need for those processes or alter them. This input generally comes from a third-party contractor.
- Document control ensures that the standards in use throughout the resource company are current and distributed throughout the organization as required.

Other changes to planning processes occur with changes to industry levels of activity. These relate to how organizations generate processes to deal with high levels of activity and inexperienced personnel. Examples of the types of changes this leads to include training programs, the need to get trainees on site to gain experience, upgrading of older rigs to provide more space, accommodation, and higher specifications.

CONTINUOUS IMPROVEMENT MEETING CHECKLIST

Objectives

- Assess whether each objective has been achieved either in accordance with or above or below the resource company's expectations.
- The subsurface team assesses the data quality, including gauge and sample data.
- Management, the HSE department, and the well test engineer assess objectives in relation to HSE and operational efficiency.

Schedule

- Identify tasks that required excessive time to complete; assess the causes behind the delays.
- Identify tasks that were completed ahead of schedule, assess the reasons, such as improved procedures, technology, and personnel experience.

Contracts

- Identify the cause behind the failures or inadequacies associated with contractor selection, contractor processes, personnel competency, and invoicing. Reference contractor learnings, contracts variations, and quotations made outside of the contracts process.

Design

- Identify the causes in relation to design inadequacies, equipment not fit for purpose, inappropriate standards, failure to apply controls, and failures to identify shortcomings in the validation process. Identify successful aspects of the design and equipment, including new technology, which provided improvements in relation to safety and the environment, and to data acquisition or time saving.

Planning Processes

- Identify issues where inadequate planning processes contributed to operational problems such as late changes to the design, inadequate planning time, and resources. Identify failures to implement planning controls, TWOP, and document controls.

Regulatory Approvals

- Were all submissions approved on first application?
- What issues, if any, did the regulator flag for attention?

Logistics

- Did the logistics plan provide the detail required by the contractors?
- Was the plan prepared in sufficient time prior to the operation?
- Was the plan distributed to every contractor?

- Were there any last-minute mobilizations of equipment due to incomplete packaging or equipment failure? Were there any personnel mobilization issues, visa issues, late arrivals, lack of safety or competency documentation, or last-minute name changes?
- Was any equipment damaged during transportation? Was all lifting documentation provided as per the logistics plan?

Well-Site Preparations

- Was the well site prepared in preparation for test equipment?
- Were all preparations as detailed in the program completed?
- Were all preparation records as per the program provided to the well test engineer, for example, pressure test charts, tool calculations, schematics, tallies, and so on?
- Were there any issues not identified in the planning documentation, including checklists, which required attention?

Well-Site Execution

- Were the heat and noise plans fully implemented and found to be adequate?
- Were all operations preceded by appropriate briefings?
- Was the Well Test Safety and Preparation Checklist completed and signed off?
- Was the Pre flow Well Test Briefing Checklist completed and signed off?

Personnel

- Were crew briefings held prior to operations?
- Did crew participate in safety management systems STOP, PTW, and so on?
- Manning levels adequate for each service? Personnel competent for their assigned tasks?
- Continuous improvement meeting held prior to demobilization?

Demobilization

- Did all contractors provide manifests?
- Did any equipment damages take place?
- Was all equipment confirmed as received by each contractor?
- Did all contractors provide well-site reports and service tickets?

MIGRATION OF KNOWLEDGE

Consider that in the preceding discussion service contractors attend a Continuous Improvement meeting to discuss operational learnings. Consider also that the same contractor may have attended prior meetings with other resource companies and will take the knowledge gained from these meeting to subsequent operations. This illustrates how knowledge can travel through service contractors from one operation to another, transferring across different client resource

companies. Because contractors specialize, they are more frequently exposed to well test operations than the resource company staff. Engaging contractors early in planning and involving them in design planning, promotes the input of learnings from a broad range of contractor experience. This input contributes significantly to the development of industry best practice.

Apart from the transfer of knowledge through movement of specialist personnel, contractor companies operate Continuous Improvement processes that maintain their own standards. As their systems and procedures evolve and as new technology improves different areas of their services, this knowledge travels throughout the contractor organization and eventually migrates into its client resource company practices.

Personnel

Resource companies often operate in several locations, and many of these companies, if not most of them, operate globally. It is common practice in these organizations to transfer personnel between locations to gain experience or to lend expertise. In so doing, personnel acquire knowledge of practices from different parts of the company organization and transfer this knowledge each time they move.

This statement applies not only to personnel transferring within the company organization from one area to another, but also through the hire of staff and contractors who bring experience from other companies into the organization.

In relation to the transfer of knowledge between personnel or communicating the company standards to new personnel, companies often rely on well-site training or on job exposure to help personnel to develop the competency skills necessary to plan and supervise well tests. Few companies maintain formal training processes for this type of work.

Regulator

Regulators issue new regulations through official documents that are made available to every resource company. The approvals process, whereby resource companies submit key planning documents to the regulator for approval prior to operations, is a control that ensures compliance with the new regulations. Most resource companies arrange to be on the distribution lists for updates, newsletters, and alerts that are periodically issued from the regulators office.

Standards Organizations

Individual resource companies access standards organizations for their latest revisions or are otherwise affiliated with the standards organization and receive the latest revisions automatically.

SERVICE VERSUS PRODUCT CONTRACTORS

Earlier in this chapter Continuous Improvement was defined as a process designed for the maintenance of standards. The services and products supplied by

contractors are delivered according to a variety of standards, the successful application of which can be measured in terms of the quality of the service or product.

Services-oriented contractors provide personnel with expertise to perform operations at the wellsite; examples include slickline, wireline, and surface well test. The scope of these services extends to support for the operation provided from contractor bases and offices.

Product-oriented companies are those that involve little or no well-site personnel expertise but may supply consumables or equipment in support of the operation, for example, contractors that supply chemicals or rental equipment.

Of the two, service-oriented companies represent higher risk to the resource company because the nature of the interaction between the two companies is more complex. Consider the training and competence levels required for well-site personnel performing hazardous operations.

Measures for the successful delivery of a service are called key performance indicators (KPIs). The resource company identifies these particular aspects of the service as important and distinct from one another. These measures become increasingly important in accordance with the risk levels associated with each service. Risk can be measured in relation to safety, cost, schedule, and reputation. For example, in relation to a contractor service that represented a high safety risk, the KPIs for that contractor will place emphasis on safety aspects of the service.

KPIs with contractors are usually established during the contracts phase, but they can also be established subsequently. KPIs include subheadings that group the different service aspects for which the resource company wishes to measure service quality. These headings could include Safety, Environment, Schedule, Technical Compliance, and Invoicing. Under each of these headings a list of specific KPI's will be identified. For example

Safety KPIs

- Crew participation in safety reporting system
- Attendance at safety meetings
- Use of the permit to work system
- Attitude toward safety
- Attendance at drills

The resource company can adjust a scoring system to each of the above to enable comparisons between operations and contracts. For example,

$$\begin{aligned} \text{Excellent} &= 4 \\ \text{Good} &= 3 \\ \text{Fair} &= 2 \\ \text{Poor} &= 1 \\ \text{Unsatisfactory} &= 0 \end{aligned}$$

In this case, the maximum score possible is 20 while the lowest is 0; anything below a 10 may warrant serious examination of the contractor's safety

and training processes. The resource company may implement controls attached to its KPIs, so that in the event a score below 10 occurred, it will implement a mandatory review of the contractor's safety processes. Most of the scoring takes place at the well site when the well test engineer fills out a set of KPIs based on each contractor's performance. Some additional scoring takes place after demobilization, for example, after the final invoicing has been completed.

The above list of KPIs reflects an emphasis on human behavior and relates to the earlier part of this discussion which identified service contractors as the high-risk contractor category because of the personnel's greater involvement with operations

THE WELL TEST ENGINEER ROLE

Budget, schedule, and well test objectives all affect well testing before the fact, and standards relating to these activities often change in response to the broader industry, such as rig availability, oil price movements, exploration results, investment calculations, and offset data. Standards and Continuous Improvement ensure that the right controls for the right procedures are instituted and that operations on critical path run smoothly and cause minimum rig downtime. This provides a sound basis for the conceptual design of new well tests, given suitable adjustments that take well data and objectives into account. A standard changes when a standards-making body publishes a new or revised standard. The market sector, represented by oil services companies and standards-making bodies, discovers new knowledge and imports it into the oil company during the initial and detailed stages of design. Those who determine company standards work in management, and they must apply their judgment in setting values and product features, using the budget, schedule, well test objectives, design criteria, and safety philosophy. Company standards consist of written procedures on how to conduct business activities such as contracting and how to perform operational activities such as pressure testing. Best practice relates to industrial know-how, whereas fit for purpose relates to engineered design tolerances for the conditions expected on the test. Using the procedures for operating tools, copied in large part from those prepared by the respective contractor service companies, the well test engineer can draw up operating standards for those who will run the process. The units might be instructions rather than mathematical figures or values. The Basis for Design sets the standard for the entire conceptual design of the well test and is the responsibility of the well test engineer. The Quality Assurance obtained from the service companies during the contracts assessment phase puts the onus on these companies to come up with best practices and fit-for-purpose designs. Much happens in Continuous Improvement without the input of the well test engineer. Nonetheless, the well test engineer has an important role to play in reviewing objectives to ensure that they are realistic. This depends on the well test engineer's judgment, with approvals from drilling management and the subsurface department.

Appendix 1: Well Test Basis For Design

Resource Company Name
Field Name
Well Name
Document Number
Revision Number

Review & Approval

Name	Position	Signature	Date
Author	Well Test Engineer		
Review	Sub surface Engineer		
Approval	Drilling Department Manager		

Distribution

Name	Position	Type	Hard Copies Qty
Name 1	Drilling Department Manager	Hard & Soft	1 copy
Name 2	Subsurface Manager	Hard & Soft	1 copy
Name 3	Well Test Engineer	Hard & Soft	1 copy
Name 4	Offshore Drilling Supervisor	Soft	
Name 5	Well Test Contractor Focal Points	Soft	
File	Document Control	Soft	

1.0. OVERVIEW

1.1. Well Test Design

Detailed well test planning shall be based on this document only. Deviations to the design shall require a revision to this document.

1.2. General Information

Example wellname will be drilled vertically to a depth of 2500 m MD RT using the rigname semi submersible MODU.

1.3. Technical Objectives

1. Determine key reservoir parameters (k, skin, D, etc)
2. Determine well deliverability and PI
3. Determine the liquid yields or CGR
4. Determine initial Reservoir Pressure (P_i)
5. Obtain representative gas samples for PVT analysis

1.4. Assumptions

1. A pip tag and pup will been included in the 7" liner and located approximately 100 m above the top of the formation sand.
2. The BOP will be pressure tested prior to the operation
3. The lower and middle rams will be configured for 5"
4. The 7" 29 ppf liner will be cemented and pressure tested to 5,000 psi
5. The 9 5/8" Wear bushing has been installed
6. A 7" Casing scraper will be run across the packer setting depths
7. The drilling mud will be displaced to 9 ppg KCL brine at the end of the casing scraper run.
8. A cement bond log will be run to confirm casing cement condition and to provide reference depths for the liner and formation.

1.5. Test Outline

A permanent seal bore packer shall be installed on wireline approximately 50m above the top of the formation sand and set inside the 7” liner.

3 3/8” TCP guns shall be fitted below a packer stinger and conveyed along with DST tools on 4 ½” PH6 15.5 ppf tubing. The stinger shall be set in compression to eliminate gauge movement due to expansion.

A diesel cushion fluid shall be used to provide an underbalance and the guns shall be activated hydraulically with surface applied pressure.

All produced fluids shall be disposed of at the flare. Metering and sampling shall take place from a test separator.

1.6. General Data

Well & Facility	
Well Name	Insert wellname
Well Type	Vertical Exploration
Permit	Insert permit licence number
Drilling Contractor	Insert drilling facility company name
Drilling Rig	Insert drilling facility name
Depth Data	
Reference	RT (Rotary table)
Depth measurements	m MD RT (Unless stated otherwise)
RT Elevation LAT	25 m
Water Depth m LAT	300 m
Deviation	Nil
Test Formation	Insert formation name
Total Depth (TD)	2500 m
Perforation Interval	2420 to 2450 m
Well Conditions	
Max BHP at TD	3600 psi
Max BHT at TD	120 Celsius
Max SITHP	3500 psi
Max THT	60 Celsius
Max Mudline Temp	80 Celsius
Reservoir Data	
Lithology	Sandstone
Porosity	10%
Permeability	10 mD
Reservoir fluid	Gas
CGR	9 STB/MMSCF
GWC	2500 m MD RT
Pressure Regime	Normally pressured

Casing & Tubing	
Production String Tubing	Nominal 4 ½”, 15.5# L80 PH6
Landing String Tubing	Nominal 4 ½”, 15.5# L80 PH6
Production Casing Data	9 5/8” 47 ppf L80 Vam Top
Production Liner Data	7”, 29 ppf L80 Vam Top
Casing Test Pressure	5,000 psi
Fluids	
Drill Fluid	SBM Synthetic Based Mud
Completion Fluid Type	NaCl Brine
Completion Fluid Weight	~9.0 ppg
Underbalance Fluid	Diesel
Underbalance Achievable	~700 psi
Test fluid	Gas
Gas SG (Air=1)	0.8
H_2S	<10 ppm
CO_2	<3%
Sand	Not expected
Emulsions/Wax	N/A
Hydrates	Possible – have occurred in offset wells
Estimated Pour Point	N/A
Test Chemicals	Methanol, Glycol
Overpressure	~200 psi (Prior to underbalance fluid)
Well Suspension	P/A
Production	
Maximum expected flowrate	60 MMSCFD
Duration	24 hours

2.0. DESIGN FEATURES

2.1. General Design Issues

2.1.1. METOCEAN

- Testing is scheduled to occur late October or early November which falls inside the cyclone (Hurricane) season for this region.
- The Resource Company cyclone response plan shall be referenced for this operation

2.1.2. HS&E CONSIDERATIONS

- Safety - High pressure gas at surface, equipment certification and test design to reflect expected conditions.
- H2S concentration low or not expected. Detailed planning will include contingency controls in the event higher than expected concentration occur.

2.1.3. HYDRATES

- Hydrate problems were encountered in several offset wells. Planning will incorporate controls to manage the associated risks.
    - Hydrate curves will be provided by the sub surface department
    - High capacity chemical injection pumps for Methanol injection
    - Steam Exchanger will be included to assist heating fluids
    - Glycol water mix will be used to pressure test equipment where required

2.1.4. MOBILISATION/DE-MOBILISATION

- Logistics support will be based at the Resource Company shore base facility located at Port name.
- All test equipment will comply with offshore lifting guidelines.
- A logistics plan will provide further detail regarding logistics support for this operation

2.1.5. DRILLING RATHOLE

- A 50 m rathole will be drilled to facilitate TCP gun release
- There are no plans to conduct wireline operations

2.1.6. LINER

- A 7” liner will be cemented in place across the formation.
- A radioactive pip tag and marker pup joint will be run with the 7” liner to aid depth correlation. This pip tag will be located above the top of the test interval and above the expected packer setting depth.
- A casing scraper will be run across the packer setting depth and the well fluid will be displaced to clean brine at this point.

2.2. Perforation

2.2.1. PRIMARY & SECONDARY SYSTEMS

- 3 3/8” HMX 12 spf guns
- Dual hydraulically actuated firing head
- Automatic gun release mechanism
- 100% contingency guns will be supplied for the operation

2.3. Downhole Test Tools

2.3.1. TEST TUBING

- 4 ½” 15.5 lb PH6 Range 2

The test string design shall be the subject of a tubing stress analysis to verify it is fit for purpose.

2.3.2. GAUGES

- Two gauge carriers shall be run in the test string positioned to provide relative gradient data. At least one gauge in the upper carrier shall be ported to measure annulus pressure.
- High resolution quartz crystal gauges
- 2 gauges will be placed on the sea bed with the ROV to record tidal information

2.3.3. DST TOOLS

- Downhole Shut in will be required to overcome wellbore storage effects.

Table 1: Test Tools Specifications

Max Outer Diameter (OD):	5″
Min Inner Diameter (ID):	2 ¼″
Working Pressure:	10,000 psi
Working Temperature:	175 °C
Connections	Premium
Service:	H_2S and CO_2

Table 2 Test Tools List

Tool	Description
Permanent Seal Bore Packer	2 7/8″ Connections below stinger & 4 ½ PH6 Box up.
2 × External Gauge Carriers	Full bore with 4 gauge capacity per carrier.
Annulus Pressure Operated Tester Valve	Provides downhole shut in includes lock open feature
Reclosable Circulating Valve	Annulus to tubing valve to spot fluids
2 × Annulus Pressure Operated Single Shot Circulating Valve	Rupture disc annulus to tubing backup circulating valve
Test string fill valve	Flapper valve for pressure testing
Subsea Test Tree (SSTT)	Test string isolation and unlatch in emergency
Lubricator Valves (LV)	To facilitate wireline operations and provide an additional barrier
Crossovers to test tubing	Supplied by contractor

2.4. Surface Well Test

Table 3 Surface Equipment Specifications

Working Pressure (HP):	10,000 psi
Working Pressure (LP):	1,440 psi
Temperature range:	-20°C to 100°C
Service:	H_2S and CO_2
Maximum Flow Rate:	60MMSCFD
General Test Pressure	5000 psi

Table 4 Flow Schedule

Period	Duration	Purpose/Remarks
Initial Flow	10 min	Clean up debris
Initial Build up	30 min	To obtain an initial reservoir pressure
Clean up	3 hours	Time estimated to remove underbalance and drilling fluid
Main Flow high	4 hours	Sampling & Productivity Measurement
Main Flow medium	4 hours	Sampling & Productivity Measurement
Main Flow low	4 hours	Sampling & Productivity Measurement
Main Flow Maximum rate	4 hours	Maximum drawdown prior to final build up
Build up	24 hours	To obtain data for build up analysis

The high to low sequence is intended to reduce the possibility of hydrate formation, an additional maximum flow rate has been included at the end of the flow period to provide maximum drawdown prior to shut in.

Table 5 Surface Test Equipment List

Item	Function
Flowhead	Well control at surface
HP Flexible Flowline	Interconnect to standpipe to accommodate vessel movement
Shutdown Valve	Secondary isolation in surface emergency shutdown
Choke Manifold	Regulate production to the surface equipment
Steam Exchanger	Assist with hydrate management
Steam Boiler	Provides steam to the steam exchanger
Separator	Metering and sampling of fluid phases
Surge Tank	To assist metering and fluid management
Chemical Injection	Assist with hydrate management
Burners	Fluid disposal
Compressors	Required for burner operation
Pipework & Manifolds	As required to interconnect the above equipment

2.5. Sampling

Detailed sampling requirements will be included in the programme. Main requirements as follows

- Pressurised condensate and gas samples for PVT recombination analysis from the surface equipment
- Non-pressurised condensate sample for assay analysis
- CO2 levels measured and recorded throughout the well test using stain tube detectors
- H2S levels to be monitored and recorded throughout the well test using stain tube detectors and taking appropriate precautions.
- Mud and brine samples will be taken prior to well testing to enable comparison with formation water.

2.6. Wireline (Electric Line)

- Cement Bond Log (CBL) inside the cemented liner – open hole. This logging pass will also identify the perforation interval in relation to the liner lap which may be used to space out the test string.
- Through tubing correlation to space out the test string

2.7. Slickline

Slickline operations shall be available as a contingency for TCP misfire troubleshooting

- 10 k Pressure control equipment (Ideally this PCE should be compatible with the E-line PCE)

2.8. Nitrogen

Nitrogen services may be required to displace the tubing brine to nitrogen to provide the desired underbalance.

2.9. Coiled Tubing

- Not required.

3.0. TEST OUTLINE AND TIME ESTIMATE

Step	Description	Hours
1. Well Preparation		
1.1	Run and cement 7” Liner	24
1.2	RIH with bit and scraper	6
1.3	Work scraper over packer setting depths	1
1.4	Circulate to clean well and pump brine, POOH bit & scraper	8

1.5	Run CBL & GR & Gauge ring	3
1.6	Make up pre-assemblies	2
1.7	BOP Test	6
	Total Well Preparation Time	**50**

2. Install Test String

2.1	RIH with Pemanent Packer body, set packer in 7” liner	4
2.2	Make up 3 3/8” TCP gun assembly	2
2.3	Make up BHA sub assemblies	4
2.4	Pressure test BHA	1
2.5	RIH on 4-1/2” 15.5 lb PH6 tubing	15
2.6	Crossover to drill pipe & continue to RIH	3
2.7	Land off locator inside packer & close pipe rams	1
2.8	POOH to top of tubing & space out with pup joints as required	3
2.9	Install subsea test tree	1
2.10	RIH 4 ½” 15.5 lb PH6 Landing string	4
2.11	Install FCH, surface lines & pressure test	3
2.12	Land off inside packer	1
2.13	Circulate diesel underbalance	3
2.14	Pressure test annulus and cycle tools to test position.	1
2.15	Hold rig floor safety meeting. Function test ESD system	1
	Total Install Test String Time	**47**

3. Well Test Production

3.1	Perforate well. Perform initial flow & build up	1
3.2	Clean up flow period	3
3.3	Main flow high rate	4
3.4	Main flow intermediate flow rate	4
3.5	Main flow low flow rate	4
3.6	Main flow maximum flow rate	4
3.7	Main Shut in period	24
	Total Well Test Production Time	**44**

4. Kill Well and Retrieve Test String

4.1	Lubricate kill fluid and bullhead kill	2
4.2	Unset packer & circulate 1 ½” hole volumes	4
4.3	Lay down surface test tree and Coflexip lines	2
4.4	POOH with test string.	18
4.5	Lay down DST tools.	3
	Total Kill Well and Retrieve Test String Time	**29**
	Total Test Time – (hours)	**170**
	Total Test Time – (days)	**7**

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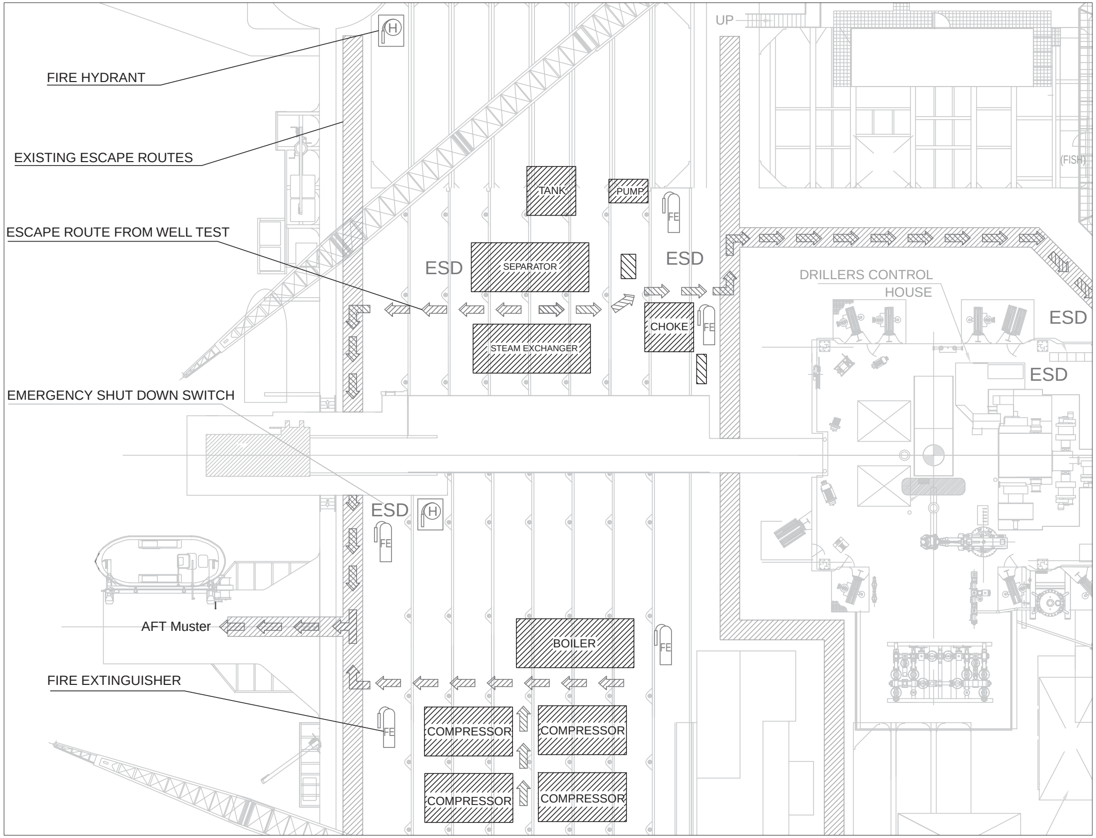
Appendix 2



WELL TEST FIRE & ESCAPE PLAN

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Appendix 3: Well Test Logistics Plan

Resource Company Name
Field Name
Well Name
Document Number
Revision Number

Review & Approval

Name	Position	Signature	Date
Author	Well Test Engineer		
Review	Logistics Superintendent		
Approval	Drilling Department Manager		

Distribution

Name	Position	Type	Hard Copies Qty
Name 1	Drilling Department Manager	Hard & Soft	1 copy
Name 2	Logistics Superintendent	Hard & Soft	1 copy
Name 3	Well Test Engineer	Hard & Soft	1 copy
Name 4	Offshore Drilling Supervisor	Soft	
Name 5	Well Test Contractor Focal Points	Soft	
File	Document Control	Soft	

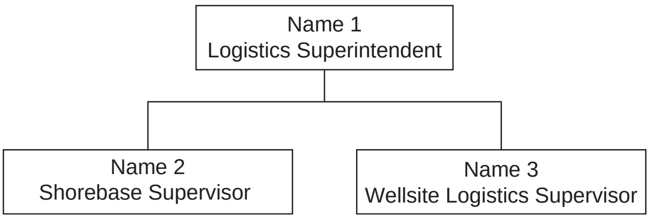
1.1. Purpose

This document details logistics planning specific to well test operations and should be read in conjunction with any existing Resource Company logistics plan for this campaign.

1.2. Logistics Contacts

The logistics superintendent based in the company head office has overall authority for managing logistics for this operation. A shore base supervisor and a wellsite logistics supervisor both report to the logistics superintendent.

Logistics personnel structure is as follows



Resource Company Logistics Contact Details

Name	Position	Phone	Email
Name 1	Logistics Superintendent	Head office phone	Name1@email
Name 2	Shore base Supervisor	Shore base phone	Name2@email
Name 3	Wellsite Logistics Supervisor	Wellsite phone	Name3@email

1.3. Equipment & Materials Movement (Shore base facility)

The Logistics Superintendent is the sole focal point responsible for authorising any equipment movements to or from the Resource Company shore base. All equipment and materials must comply with the following requirements.

1. A shipping manifest/consignment must accompany all equipment and materials.
2. All shipments must be addressed as follows
   For the attention of Name 2 Shore base Supervisor
   Well Test Equipment
   Resource Company Name
   Shore base address
3. The manifest/consignment notes must detail each individual load weight and dimensions and also provide an item description for every lift.

4. All lifts must be certified in accordance with the Resource Company lifting standard e.g. Latest revision of EN12079.
5. Lifting certification must be made available to the shore base supervisor in respect of each lift.
6. All dangerous goods must be clearly marked and accompanied by appropriate supporting documentation including MSDS.
7. The Resource Company Logistics Superintendent shall arrange for all trucking, cranes & airfreight unless by prior arrangement with the Logistics Superintendent. Invoices in respect of unauthorised shipments shall not be paid.

1.4. Equipment & Materials Movement (Wellsite facility)

The movement of equipment to or from the wellsite shall be the responsibility of the wellsite logistics supervisor. The wellsite logistics supervisor will liaise with the resource company drilling supervisor and the well test engineer to plan equipment movements to and from the wellsite. Requirements for any such movements are the same as 1.3.

1.5. Personnel Movements

Personnel travel to or from the wellsite shall be the responsibility of the wellsite logistics supervisor, who will forward check in and itinerary's to each contractor focal point for distribution to contractor personnel.

Personnel will travel from the airport to the offshore facility via helicopter. The helicopter check in is located inside the airport terminal and is clearly marked.

The offshore drilling facility is located 100 kms from the airport, in order to manage POB, and to prioritise personnel according to operations, the wellsite logistics supervisor will liaise with the resource company drilling supervisor and the well test engineer to plan personnel movements to or from the wellsite.

Unless by prior arrangement, the airport shall be designated point of origin for all contractor personnel. Contractor personnel are responsible for arranging their own travel to and from the airport.

Personnel travelling to or from an offshore facility must comply with the following

1. Resource Company drug and alcohol policy
2. Each person shall carry a maximum of 15 kg with no individual bag to exceed 10 kg, except by prior arrangement 24hours in advance of travel.
3. No loose objects, hats, newspapers or magazines shall be carried on board a helicopter
4. Mobile phones must be turned off and handed to the airport helicopter security staff.
5. Personnel must undergo security checks at the airport

6. All personnel must produce current helicopter safety training cards which comply with OPITO.
7. All personnel shall receive a pre-flight safety briefing prior to boarding a helicopter when travelling offshore or returning to the airport.

Appendix 4: Well Test Equipment Inspection Guideline

Resource Company Name
Field Name
Well Name
Document Number
Revision Number

Review & Approval

Name	Position	Signature	Date
Author	Well Test Engineer		
Review	Drilling Supervisor		
Approval	Drilling Department Manager		

Distribution

Name	Position	Type	Hard Copies Qty
Name 1	Drilling Department Manager	Soft	
Name 2	Well Test Engineer	Hard & Soft	1 copy
Name 3	Contractor Focal Point	Hard & Soft	1 copy
File	Document Control	Soft	

1.1. Purpose

This document provides a guide for use by the well test engineer when conducting pre-mobilisation inspections of contractor well test equipment. A separate inspection is required for every well test service. The intent of the document is to help ensure the equipment provided for each service is complete and fit for purpose.

1.2. Visiting Contractor or Resource Company Facilities

The following steps should be completed in advance of an inspection

1. Arrange a convenient time for the inspection with the contractor focal point.
2. Forward a copy of the checklist to the contractor focal point so that they are aware of the scope of the inspection
3. Obtain a complete list of equipment for load out from the focal point prior to the inspection.
4. Review the equipment list against the contract and against the planning documentation (Program, Well Test Design Package) to ensure that it is in accordance with the well test design.
5. Confirm with the contractor or facility supervisor any special requirement in relation to visiting the facility, PPE, inductions, contacts, other?

1.3. Checklist Instructions

- Inspections must be completed by the well test engineer
- Where applicable utilise the approved P & ID during each inspection
- Check only those boxes relevant to the equipment being inspected.
- Mark as N/A any item not relevant to the inspection.
- On completion, this document must be handed to document control for filing and distribution.

1.4. Contractor Details

1. Contractor Name
2. Service
3. Date of Inspection
4. Name of contractor focal point
5. Address of facility

1.5. Inspection Checklist

Description	Check
Equipment List	
Confirm every item on the P & ID or equipment list has been supplied	
Certification	
Confirm each component serial number matches the certification supplied	
Confirm all relevant certification for each component is complete. Refer to certification matrix as a guide	
Confirm certification will not expire during the course of the operation	
Confirm service records complete, in particular checklists do not have blank spaces or omissions.	
Pressure Equipment	
Visually inspect all components for damage, wear, pitting corrosion on seal faces loose fittings, flanges or identity tags and general appearance.	
Inspect at random at least 3 NPT fittings on pressure bearing components for thread damage or corrosion.	
Inspect flanges and confirm studs and nuts are fully engaged on both sides	
Confirm flange studs are in good condition and carry material stamps e.g. B7 or equivalent.	
Safety Devices	
Inspect all safety devices, in particular Pressure Relieving Devices, PSV's & Rupture discs. Confirm identity tags indicating calibration, installation date and setting are fitted to each and in accordance with the P & ID	
Ensure appropriate safety equipment has been packed. Safety signs, barrier tape, PPE, safety clips, tie down chain, fire extinguishers, oil spill kits.	
Electrical	
Confirm all electrical equipment has been serviced and inspected by an accredited specialist	
Inspect cables are appropriate for application, e.g. armoured cable for pumps and office containers	
Inspect seals at cable terminations are tight and in good order	
Ensure adequate length cables have been supplied for each item	
Inspect electrical junction boxes to ensure they are secure and that air tight where applicable	

Hoses

Inspect all hoses for identity bracelets or stamps
Ensure each hose is rated for intended service, i.e. Steam, Hydrocarbons, Water etc.
Inspect end fittings and clamps are secure and of the correct type
Inspect hoses for cracks, tears or other damage

Packing

Inspect baskets to ensure equipment has been packed securely so as to avoid damage during transport. Dunnage such as wood batons should be used to separate components and secured with straps or otherwise tied down to minimise movement
Confirm a packing list has been completed for each basket
Inspect containers to ensure contents are complete and securely packed.

Lifting Gear

Confirm each lift is provided with its own lifting gear
Confirm lifting gear is secured with 4-point shackles and split pins
Confirm each lift is fitted with a lifting certification plate and the inspections stamped on the plate are current
Confirm lifting slings are provided with tags showing current inspection data
Inspect lift for loose objects which could fall or cause damage during transit
Confirm each lift is clearly marked with an individual identifier

1.6. Certification Frequency

Certification	Standard	Acceptance Criteria
COC, IRC, Type Approval	DNV, ABS, BV or equivalent	No expiry
Major Survey	DNV, ABS, BV or equivalent	60 Months
Hydro Test	Resource/Contractor Company/API	12 Months or Per Operation
Calibration Certificate Electronic Equipment	OEM	12 Months or as per OEM guideline
Calibration Certificate Safety Devices	Local Regulations/API 520 & 521	12 Months
Calibration Certificate Pressure Test Facility	BV/DNV/Equivalent	12 Months
Electrical Certification	Local Regulations	Per Operation

1.7. Certification Matrix

Item	COC	Major Survey	Hydro Test (Annual)	Load Test	Service Record	Electrical Certificate	Calibration Certificate	Confirm S/N	Check
Pressure test pump									
Bails									
Flowhead									
HP Hose									
HP Hose									
Shutdown Valve									
HP Pipework									
Data header									
Choke Manifold									
LP Pipework									
Steam Exchanger									
Steam Jacket PSV									
Boiler									
Boiler PSV									
Separator									
Separator PSV 1									
Separator PSV 2									
Oil Manifold									
Oil Diverter									
Gas Diverter									
Gauge Tank									
Surge Tank									
Surge Tank PSV									
Transfer Pump									
Kingpost Port									

Kingpost STBD									
Boom Port									
Boom STBD									
Burner Head Port									
Burner Head STBD									
Ignition system port									
Ignition system stbd									
ESD System									
Data Acquisition									
Downhole Gauges									
Lab Cabin									
Knock out vessel									

Equipment Inspection Certificate

This document certifies that the equipment covered by this inspection has been accepted as fit for purpose by the Resource Company and is ready for mobilisation to the well site.

Signed

Name 1
Resource Company – Well Test Engineer

Appendix 5: Well Test Program

Resource Company Name
Field Name
Well Name
Document Number
Revision Number

Review & Approval

Name	Position	Signature	Date
Author	Well Test Engineer		
Review	Sub surface Engineer		
Review	Drilling Supervisor		
Approval	Drilling Department Manager		

Distribution

Name	Position	Type	Hard Copies Qty
Name 1	Drilling Department Manager	Hard & Soft	1 copy
Name 2	Subsurface Manager	Hard & Soft	1 copy
Name 3	Well Test Engineer	Hard & Soft	1 copy
Name 4	Offshore Drilling Supervisor	Soft	
Name 5	Well Test Contractor Focal Points	Soft	
Name 6	Wellsite distribution	Hard	10 Copies
File	Document Control	Soft	

REFERENCES

1. Well Test Personnel Roles and Responsibilities
2. Wellsite Well Test Equipment Preparation Checklist
3. Pressure Test Guideline
4. Facility Safety Management Systems
5. Contractor Procedures

1.0. OVERVIEW

1.1. Purpose

The purpose of this program is to ensure that the planning decisions regarding the conduct of the well test are properly implemented. This program is intended as the principal reference for the conduct of the well test operation; it contains the procedures required for the wellsite execution of the well test and also includes references to contractor procedures which relate to the operation or handling of contractor specific equipment.

1.2. Management of Change

Deviations to the procedures in this program are subject to management of change controls. The Drilling Supervisor together with the Well Test Engineer will assess each change in order to determine if it requires written approval from head office. Small changes which do not entail significant safety or operational risks may be made with the authority of the Drilling supervisor and the Well Test Engineer provided such changes are subject to risk assessment.

1.3 Well and Reservoir Data

Well & Facility	
Well Name	Insert wellname
Well Type	Vertical Exploration
Permit	Insert permit licence number
Drilling Contractor	Insert drilling facility company name
Drilling Rig	Insert drilling facility name
Depth Data	
Reference	RT (Rotary table)
Depth measurements	m MD RT (Unless stated otherwise)
RT Elevation LAT	25m
Water Depth m LAT	300m
Deviation	Nil
Test Formation	Insert formation name
Total Depth (TD)	2500 m
Perforation Interval	2420 to 2450 m
Well Conditions	
Max BHP at TD	3600 psi
Max BHT at TD	120 Celsius
Max SITHP	3500 psi
Max THT	60 Celsius
Max Mudline Temp	80 Celsius

Reservoir Data	
Lithology	Sandstone
Porosity	10%
Permeability	10 mD
Reservoir fluid	Gas
CGR	9 STB/MMSCF
GWC	2500 m MD RT
Pressure Regime	Normally pressured
Casing & Tubing	
Production String Tubing	Nominal 4 ½", 15.5# L80 PH6
Landing String Tubing	Nominal 4 ½", 15.5# L80 PH6
Production Casing Data	9 5/8" 47 ppf L80 Vam Top
Production Liner Data	7", 29 ppf L80 Vam Top
Casing Test Pressure	5,000 psi
Fluids	
Drill Fluid	SBM Synthetic Based Mud
Completion Fluid Type	NaCl Brine
Completion Fluid Weight	~9.0 ppg
Underbalance Fluid	Diesel
Underbalance Achievable	~700 psi
Test fluid	Gas
Gas SG (Air=1)	0.8
H_2S	<10 ppm
CO_2	<3%
Sand	Not expected
Emulsions/Wax	N/A
Hydrates	Possible – have occurred in offset wells
Estimated Pour Point	N/A
Test Chemicals	Methanol, Glycol
Overpressure	~200 psi (Prior to underbalance fluid)
Well Suspension	P/A
Production	
Maximum expected flowrate	60 MMSCFD
Duration	24 hours

1.4. Technical Objectives

1. Determine key reservoir parameters (k, skin, D, etc)
2. Determine well deliverability and PI
3. Determine the liquid yields or CGR

4. Determine initial Reservoir Pressure (P_i)
5. Obtain representative gas samples for PVT analysis

1.5. Assumptions

1. A pip tag and pup joint have been included in the 7" liner and located approximately 100 m above the top of the formation sand.
2. The BOP has been pressure tested prior to the operation
3. The lower and middle rams are configured for 5"
4. The 7" 29 ppf liner has been cemented and pressure tested to 5,000 psi
5. Setting depths are as per the Basis For Design.
6. The 9 5/8" Wear bushing has been installed
7. A 7" Casing scraper has been run across the packer setting depths
8. The drilling mud has been displaced to 9 ppg brine at the end of the casing scraper run.
9. A cement bond log has been run and depths to the formation confirmed

1.6. Roles and Responsibilities

The roles and responsibilities for personnel involved with the well test are detailed in a separate controlled document Well Test Operation Personnel Roles and Responsibilities.

1.7. Test Outline

A permanent seal bore packer shall be installed on wireline approximately 50 m above the top of the formation sand and set inside the 7" liner.

3 3/8" TCP guns shall be fitted below a packer stinger and conveyed along with DST tools on 4 ½" PH6 15.5 ppf tubing. The stinger shall be set in compression to eliminate gauge movement due to expansion.

A diesel cushion fluid shall be used to provide an underbalance and the guns shall be activated hydraulically with surface applied pressure.

All produced fluids shall be disposed of at the flare. Metering and sampling shall take place from a test separator.

2.0. PREPARATIONS

2.1. All Contractors

- Perform inventory checks on all equipment
- Inspect equipment for transport damage
- Report to the Well Test Engineer
- Any contractor performing hazardous activities such as pressure testing, working at heights, electrical work, and handling of dangerous goods must comply with the safety management systems, permits, JSA etc.
- All pressure test charts must be provided to the Well Test Engineer, each chart clearly labelled.

2.2. TCP Preparations

- Determine required perforation interval from Well Test Engineer
- Load guns in accordance with contractor specific handling procedures and with the facility safety management systems.
- Strap guns on deck and number each item in order of its installation. Measurements must be witnessed by the Well Test Engineer.
- Confirm well conditions and perform firing head calculations, provide calculations to the Well Test Engineer
- Prepare sub assembly drawings showing dimensions and TCP firing head settings.

2.3. DST Preparations

- Confirm well conditions and required operating settings for tools.
- Pressure test tools & assemblies on deck as per contractor test procedures to the general test pressure, record all tests on a chart
- Well Test Engineer to witness the installation of rupture discs and shear pins.
- Review string movement calculations to ensure correct packer weight or packer seal bore spaceout
- Prepare sub assembly drawings with dimensions and tool settings

2.4. Tubing Preparations

- Layout, clean and inspect tubing and pup joint end connections, drift all tubulars.
- Strap (measure) each joint, use overall length dimensions only, made up lengths will be subtracted in the tally, paint length and number on each joint.
- Prepare a tubing tally with all tubing lengths and numbers
- Include space out pups
- Remove end protectors, clean and inspect threads in preparation for running

2.5. Tubing Handling Equipment

- Function test tongs and power pack on deck
- Function test make-up computer and ensure correct tubing torque settings are programmed
- Check tubing dies are the correct size and type for the test tubing
- Ensure back-up equipment is to hand should it be required

2.6. Subsea Preparations

- Prepare an assembly drawing showing the spaceout of the Subsea test tree inside the BOP. Include all relevant dimensions.

- Function and pressure test the subsea test tree and lubricator valves on deck. Function testing should include the full length umbilicals for each valve.
- Confirm umbilical length is appropriate for installation
- Install a full single joint of tubing and short saver pup below the flowhead
- Make up SSTT sub assembly with a 2 m handling pup above and a short saver pup below
- The Well Test Engineer will witness all assemblies strapped
- Prepare sub assembly drawings with dimensions and provide same to the Well Test Engineer.

2.7. Surface Equipment Preparations

- Surface equipment laid out and assembled in accordance with the layout and P & ID drawings.
- Confirm relief valves and automatic shutdown switches are situated in accordance with the P & ID and that the settings and calibrations are correct.
- Review pressure test procedure with Well Test Engineer, pressure test surface equipment as per contractor procedures and in accordance with the facility safety management systems, permits, JSA etc.
- Function test the boiler, compressors and burner head ignition system.

2.8. Data Acquisition Preparations

- Confirm type and number of gauges supplied are as per program
- Confirm gauge calibrations are current
- Confirm gauges are function and pressure tested on deck
- Confirm gauges are setup as specified in the program or as directed by the Well Test Engineer.
- Confirm a new battery is installed into each gauge and that each battery has been checked.

2.9. Slickline Preparations

- Assemble pressure control equipment and pressure test as per contractor procedures and in accordance with the facility safety management systems permit, JSA etc.
- Function test winch unit and power pack.
- Inspect wire drum and perform torsion tests on wire.
- Inspect weight indicator and depth counter
- Function test air winch for handling pressure control equipment
- Prepare a pressure control equipment assembly drawing including dimensions to confirm adequate height available for installation.
- Prepare string diagrams for all potential operations.

2.10. Fishing Equipment

- Review inventory of fishing equipment supplied matches the range of equipment to be installed in the test string
- Ensure specialised fishing equipment supplied separately is available. e.g. subsea fishing equipment

2.11. Well Test Engineer

- Complete wellsite Well Test Equipment Preparation Checklist
- Prepare Running Tally

3.0. CRITICAL PATH PROCEDURES

3.1. Pre Assemblies

3.1.1. Conduct JSA – handling pre-assemblies
3.1.2. Clear drill floor of unnecessary equipment
3.1.3. Change handling gear to 5" Drill Pipe for flowhead
3.1.4. Pick up tubing handling equipment
3.1.5. Pick up flowhead assembly and make up as directed by the subsea contractor supervisor
3.1.6. Lay out flowhead
3.1.7. Pick up SSTT assembly and make up as directed by the subsea contractor supervisor

3.2. Packer Installation

3.2.1. Conduct JSA – Wireline operations
3.2.2. Pick up the packer body assembly fitted to the wireline as directed by the packer specialist
3.2.3. RIH with packer body assembly on wireline to approximately 20 m below the proposed setting depth
3.2.4. Correlate packer setting depth against the casing pip tag
3.2.5. Set packer on depth as directed by the Well Test Engineer
3.2.6. POOH with wireline & packer setting tool

3.3. Test String Installation

3.3.1. Conduct JSA – TCP Guns & Tubing handling
- Ensure well control crossovers are available on the drill floor and connected to the TIW valve

3.3.2. Pick up TCP Guns and accessories as per the running tally and make up as directed by the TCP specialist
3.3.3. Pick up packer locator and make up to top of TCP gun assembly as directed by the packer specialist

3.3.4. Pick up DST tools and assemblies as per the running tally and make up as directed by the DST tools specialist
- Running speed should not exceed the equivalent of 90 secs per stand
- Set slips softly
- Engage compensators as packer passes the BOP and wellhead

3.3.5. Pick up the first 3 joints of 4 ½" PH6 15.5 ppf tubing, install crossover to drill pipe and pressure test BHA to 5000 psi as per the pressure test guideline

3.3.6. Continue to RIH with 4 ½" PH6 15.5 ppf tubing as per running tally
- Engage compensators as packer enters the liner
- In the event the string hangs up, call the Well Test Engineer immediately

3.3.7. Install crossover to drill pipe as indicated on the tally where it is intended to install the SSTT, continue to RIH with 5" drill pipe
- Ensure first joint of pipe is painted white

3.3.8. Engage compensators as the TCP guns enter the seal bore packer

3.3.9. Perform pick up and slack off weight checks

3.3.10. Continue to RIH with test string note any weight loss corresponding to packer seals entering the packer body

3.3.11. Land off with 10,000 lbs slack off weight to ensure locator has fully landed out

3.3.12. Crosscheck depth against running tally

3.3.13. Pick up and repeat the above land off to confirm spaceout

3.3.14. Pick up to spaceout locator as required and mark the pipe at the rotary table

3.3.15. Close pipe rams on painted joint

3.3.16. Open pipe rams and POOH to top of tubing
- Measure the distance from the ram marks to the top of the tubing measurement A
- Subtract the length of the SSTT assembly from the mid point of the slick joint to the bottom of the assembly measurement B

3.3.17. Install spaceout pup joints to make up the difference between A & B
- It is recommended to install the pup joints below a full joint to facilitate variable ram closure when the string is later retrieved

3.3.18. Conduct JSA – Landing string installation

3.3.19. Pick up and install the SSTT assembly as directed by the Subsea Specialist

3.3.20. Attach umbilicals and secure umbilicals to tubing with clamps or tape as pre-arranged

3.3.21. Continue to RIH with 4 ½" PH6 15.5 ppf tubing as per running tally

3.3.22. Pick up and install the lubricator valve assembly as directed by the Subsea Specialist

3.3.23. Conduct JSA – Flowhead Installation

3.3.24. Install top drive sub and slickline air winch
3.3.25. Install extended bail arms shackled to the drilling bails using 85 t shackles
3.3.26. Install 5” drill pipe elevators
3.3.27. Pick up flowhead and make up as directed by the subsea specialist
3.3.28. Install control lines, crossovers and high pressure flexible hoses
3.3.29. Pressure test the test string, flowhead and surface lines as per pressure test program
3.3.30. Perform pick up and slack off weight checks
3.3.31. Engage compensators
3.3.32. Ensure production valve on flowhead is open to the well test package
- This step ensures that a hydraulic lock does not occur when the locator seals enter the packer body

3.3.33. Land off at wellhead
3.3.34. Retain flowhead and landing string weight with blocks

3.4. Commissioning & Underbalance

3.4.1. Conduct – JSA pressure testing and diesel pumping operations
3.4.2. Close pipe rams
3.4.3. Pressure annulus from cement unit to 1000 psi this will lock open the flapper, and activate the tester valve reference tool and will also test the packer seal
3.4.4. Cycle the re-closable circulating valve to the open position
3.4.5. Displace diesel to the test string
- The volume displaced will be equivalent to the test string volume to the circulating valve less 5 bbls
- This will provide an underbalance pressure of ~700 psi

3.4.6. Close circulating valve
3.4.7. Function test ESD system

3.5. Perforation

3.5.1. Conduct Pre Test Safety Meeting – Refer to Wellsite Well Test Preparation Checklist
3.5.2. Apply pressure to annulus to open the tester valve
- Note the volumes pumped to achieve activation pressure

3.5.3. Pressure tubing to calculated TCP activation pressure and hold as directed by TCP specialist
3.5.4. Bleed off pressure to 50 psi at surface and monitor at choke manifold
- TCP firing head is fitted with a delay which activates the guns ~15 mins after pressure hs been removed

3.6. Clean Up & Flow

3.6.1. Once a positive indication that the guns have fired has been observed, open the well on a ¼" adjustable choke to the surge tank and continue flowing for 10 mins

3.6.2. Bleed off at annulus to close the tester valve downhole, when a pressure drop is observed at surface close the choke manifold

3.6.3. Remain shut in for 30 mins or as directed by the Well Test Engineer

3.6.4. Ensure the boiler is running prior to the clean up flow

3.6.5. Pressure annulus to open the tester valve, when a pressure increase is observed at surface, open the choke manifold on a ¼" adjustable choke to the surge tank

3.6.6. Continue to increase the choke as directed by the Well Test Engineer or as dictated by the operational need to allow the well to clean up

3.6.7. Direct flow to the burners once a sufficient wellhead pressure is available to ensure a good burn

3.6.8. Increase choke to the maximum rate to achieve the best possible clean up. Inject methanol as required to manage hydrates
- Switch to a fixed choke when conditions have stabilised
- Record the estimated flow rate as the choke is increased during the clean up

3.6.9. Monitor fluids during the clean up, when the clean up criteria have been met, the 1st main flow period shall commence
- Clean up criteria are 3 successive BSW measurements <1% & stable wellhead pressure
- Direct flow through separator for main flow periods
- Take samples as required according to the sampling programme

3.6.10. After 4 hours reduce to a fixed choke to provide an intermediate flow rate as specified by the Well Test Engineer
- Take samples as required according to the sampling programme

3.6.11. After 4 hours reduce to a fixed choke to provide the lowest flow rate as specified by the Well Test Engineer
- Take samples as required according to the sampling programme

3.6.12. After 4 hours, increase the choke to the maximum rate to achieve maximum drawdown prior to shut in

3.6.13. After 4 hours, bleed off annulus pressure to close tester valve, when a pressure drop is observed at surface, close the choke manifold

3.6.14. Remain shut in for 24 hours or as directed by the Well Test Engineer

3.7. Well Kill & Test String Retrieval

3.7.1. At the end of the build up period, open the choke manifold and bleed surface pressure to 0 psi

3.7.2. Lubricate 9.0 ppg KCL brine into the string through the kill valve of the flowhead using the cement unit to fill the test string

3.7.3. Pressure annulus to open the tester valve
3.7.4. Bullhead 9.0 ppg KCL brine into the formation, pump at least the volume from the tester valve to the perforations or until a sharp rise in pressure indicates the brine fluid has reached the formation
3.7.5. Flow check for 15 minutes
3.7.6. Cycle the tester valve to the lock open position
3.7.7. Open pipe rams & pick up on flowhead to un-sting from the packer
3.7.8. Circulate 1.5 hole volumes of 9.0 ppg KCL brine using the mud pumps
3.7.9. Flow check for 15 minutes
3.7.10. Conduct JSA – Flowhead removal
3.7.11. Break out the surface lines and the flowhead
3.7.12. Remove extended bails
3.7.13. Prepare tubing handling equipment
3.7.14. Commence POOH with tubing lay out joints
3.7.15. Layout SSTT assembly to be picked up later for break out
3.7.16. Continue POOH with test string
- Ensure TCP, DST, Subsea and Packer specialists are present on the drill floor as their respective tools reach surface

3.7.17. End of program, refer to Drilling Program for P & A procedures

4.0 Test outline and Time Estimate

Step	Description	Hours
1. Well Preparation		
1.1	Run and cement 7” Liner	24
1.2	RIH with bit and scraper	6
1.3	Work scraper over packer setting depths	1
1.4	Circulate to clean well and pump brine, POOH bit & scraper	8
1.5	Run CBL & GR & Gauge ring	3
1.6	BOP Test	6
	Total Well Preparation Time	**48**
2. Install Test String		
2.1	Make up pre-assemblies	2
2.2	RIH with Permanent Packer body, set packer in 7” liner	4
2.3	Make up 3 3/8” TCP gun assembly	2
2.4	Make up DST sub assemblies	4
2.5	Pressure test BHA	1
2.6	RIH on 4-1/2” 15.5 ppf PH6 tubing	15
2.7	Crossover to drill pipe & continue to RIH	3
2.8	Land off locator inside packer & close pipe rams	1
2.9	POOH to top of tubing & space out with pup joints as required	3

2.10	Install subsea test tree	1
2.11	RIH 4 ½" 15.5 ppf PH6 Landing string	4
2.12	Install Flowhead, surface lines & pressure test	3
2.13	Land off inside packer	1
2.14	Circulate diesel underbalance	3
2.15	Pressure test annulus and cycle tools to test position.	1
2.16	Hold rig floor safety meeting. Function test ESD system	1
	Total Install Test String Time	**49**
3. Well Test Production		
3.1	Perforate well. Perform initial flow & build up	1
3.2	Clean up flow period	3
3.3	Main flow high rate	4
3.4	Main flow intermediate flow rate	4
3.5	Main flow low flow rate	4
3.6	Main flow maximum flow rate	4
3.7	Main Shut in period	24
	Total Well Test Production Time	**44**
4. Kill Well and Retrieve Test String		
4.1	Lubricate kill fluid and bullhead kill	2
4.2	Unset packer & circulate 1 ½" hole volumes	4
4.3	Lay down Flowhead and surface lines	2
4.4	POOH with test string.	18
4.5	Lay down DST tools.	3
	Total Kill Well and Retrieve Test String Time	**29**
	Total Test Time – (hours)	**170**
	Total Test Time – (days)	**7**

5.0. APPENDIX A CONTINGENCY PROCEDURES

5.1 Tubing Leak – Contingencies

Tubing Leak	Observed Condition	Procedure
Inside Riser	Drop in tubing pressure Gas release on drill floor	Close SSTT Close Tester Valve Bleed landing string pressure

Tubing Leak	Observed Condition	Procedure
Below SSTT	Drop in tubing pressure Initial increase in annulus pressure Circulating valve opens Kill weight fluid in annulus flows into test string Losses at trip tank - well self kills	Maintain kill fluid supply to annulus
Lower Test String	Drop in tubing pressure Kill weight fluid in annulus flows into test string Losses at trip tank - well self kills	Maintain kill fluid supply to annulus

5.2. TCP Misfire

5.2.1. Wait 2 x times the calculated delay time
5.2.2. Confirm valve configuration
5.2.3. Confirm TCP firing head calculation
5.2.4. Apply maximum firing head pressure and hold as directed by TCP specialist
- Record volumes pumped to achieve maximum pressure and compare with previous figures

5.2.5. Wait 2 x times calculated delay time
5.2.6. Confer with head office
5.2.7. Prepare to rig up slickline pressure control equipment to run drift to firing head to ensure communication path
5.2.8. If communication path is established, RIH to retrieve firing head on slickline
5.2.9. Re-dress and re-run firing head if problem identified
5.2.10. If above procedure fails again, prepare to retrieve test string

5.3. Emergency Disconnect – Recommended

5.3.1. Bleed annulus pressure to close tester valve
5.3.2. Bleed tubing pressure to 0 psi
5.3.3. Lubricate 9.0 ppg KCL brine above the tester valve
5.3.4. Apply annulus pressure to open tester valve and bullhead fluid into formation
5.3.5. Flow check for 15 minutes
5.3.6. Bleed annulus pressure to close tester valve
5.3.7. Adjust string weight to ensure SSTT is not in tension
5.3.8. Close SSTT

5.3.9. Activate hydraulic unlatch feature
5.3.10. Pick up on landing string to above the blind rams
5.3.11. Close blind rams
5.3.12. Recover landing string

5.4. Emergency Disconnect – Insufficient time to Bullhead

5.4.1. Bleed annulus pressure to close tester valve
5.4.2. Bleed tubing pressure to 0 psi
5.4.3. Lubricate 9.0 ppg KCL brine above the tester valve
5.4.4. Adjust string weight to ensure SSTT is not in tension
5.4.5. Close SSTT
5.4.6. Activate hydraulic unlatch feature
5.4.7. Pick up on landing string to above the blind rams
5.4.8. Close blind rams
5.4.9. Recover landing string

5.5. Emergency Disconnect – Immediate Disconnect

5.5.1. Adjust string weight to ensure SSTT is not in tension
5.5.2. Close SSTT
5.5.3. Activate hydraulic unlatch feature
5.5.4. Pick up on landing string to above the blind rams
5.5.5. Close blind rams
5.5.6. Recover landing string

6.0 Appendix B Casing and Tubing Data

	OD (in)	ID (in)	Drift (in)	Make Up Torque (ft-lbs)
4 ½” PH6 L80 15.5 ppf	4.500	3.826	3.701	6000 ft-lbs Minimum 7500 ft-lbs Maximum
7” Vam Top L80 29 ppf	7.000	6.184	6.059	
9 5/8” Vam Top L80 47 ppf	9.625	8.681	8.525	

7.0. APPENDIX C LAYOUT DRAWING

Refer to figure 6.4

8.0. APPENDIX D P & ID

Refer to figure 5.21

Appendix 6: Roles and Responsibilities during a Well Test

Resource Company Name
Field Name
Well Name
Document Number
Revision Number

Review & Approval

Name	Position	Signature	Date
Author	Well Test Engineer		
Review	Drilling Supervisor		
Approval	Drilling Department Manager		

Distribution

Name	Position	Type	Hard Copies Qty
Name 1	Drilling Department Manager	Hard & Soft	1 copy
Name 2	Subsurface Manager	Hard & Soft	1 copy
Name 3	Well Test Engineer	Hard & Soft	1 copy
Name 4	Offshore Drilling Supervisor	Soft	
Name 5	Well Test Contractor Focal Points	Soft	
File	Document Control	Soft	

1.0. PURPOSE

Resource Company and Contractor personnel duties frequently change when an operation moves from Drilling or Completions to Well Test. This

document details specific roles and responsibilities for personnel in connection with well test operations.

This document forms an appendix to the Well Test Program.

2.0. ROLES AND RESPONSIBILITIES

2.1. All Personnel

All personnel at the facility have obligations to comply with regulations and policies, specifically

- Comply with and support the safety management systems in effect.
- Comply with drug and alcohol policies
- Attend drills, safety meetings, toolbox talks, JSA's, flight briefings and others as may be required
- Wear appropriate PPE at all times
- Listen to and adhere to safety announcements and obey barrier signs and warnings.

2.2. Offshore Installation Manager (OIM)

The OIM is in authority on board the facility and has overall responsibility for the safety of the facility and its personnel.

Specific responsibilities include:

- Facility safety management system
- Facility safety equipment
- Fire and rig evacuation drills.
- Availability of support vessels for standby duties
- Coordinate and report actions to prevent and remedy any adverse effect on the safety of personnel, the environment or equipment
- Additional duties in relation to the day to day management of the facility
- Reporting obligations to the facility Owners, the Client Resource Company and the Regulator.

2.3. Offshore Drilling Supervisor

The Drilling Supervisor is operationally responsible for managing the execution of Resource Company programs, including Drilling and Well Test programs.

Specific responsibilities include:

- Report operations status to the OIM
- Work with the OIM to ensure that operations are performed in a safe manner
- Issue notifications to regulatory and other facilities where operations require.
- Reporting to the Resource Company head office.

- Coordinate contractors engaged by the Resource Company in support of Drilling operations
- Providing support to the Well Test Engineer in relation to management of the facility during well test operations
- Ensure the well is secure both during and after well test operations.

2.4. Offshore Logistics Coordinator

The logistics coordinator reports directly to the Drilling Supervisor

Specific responsibilities include:

- Work with the Drilling Supervisor and the Well Test Engineer to plan equipment and personnel movements in support of operations
- Communicate equipment movements and deck space requirements to deck crews
- Supervise the loading and unloading of supply vessels and the management of space on deck
- Track equipment and material movements
- Prepare manifests, consignment notes, dangerous goods paperwork etc for all equipment and material movements
- Liaise with the shorebase supervisor and the Logistics Superintendent at head office in support of equipment and personnel movements.
- Arrange for flight bookings and the issue of itineraries for personnel travelling to and from the facility

2.5. Toolpusher

The Toolpusher reports to the OIM but also has an operational reporting role to the Drilling Supervisor.

Specific responsibilities include:

- Manage drill crews in support of the well test operations
- Maintain an accurate drill pipe tally
- Review procedures for well test operations which involve drill crew personnel
- Relieve the Driller as required
- Ensure BOP is tested maintained in readiness for well test operations

2.6. Driller

The Driller reports to the Toolpusher and is responsible for supervising activity on the drill floor and for the operation of drilling equipment.

Specific responsibilities include:

- The driller is responsible for the operation of drilling equipment including the BOP, Pump systems, Top Drive & Compensators.

- Ensure running tools, slips, elevators, dog collars etc are available on the rig floor in preparation for each procedure in the program.
- Ensure well control crossovers and related equipment are to hand during well test operations
- Maintain an accurate count on the running tally during the test string installation and retrieval
- Act as focal point for communication during well test operations.
- Monitor and update the valve configuration for downhole valves and the Flowhead.
- Remain on the drill floor with two floormen at all times during Well Test operations other than when relieved by the Toolpusher.

2.7. Contractor Well Test Supervisor

The contractor well test supervisor reports directly to the Well Test Engineer
Specific responsibilities include

- Supervision of well test personnel
- Installation, commissioning and operation of well test related equipment.
- Review well test procedures with well test crew and ensure the response of well test personnel to emergency alarms during a test are understood.
- Manage interfaces between other services such as sampling
- Liaise with the Well Test Engineer and other contractors to assist and advise in planning and to help ensure interfaces between operations are seamless

2.8. Tubing Handling Services Supervisor

Reports directly to the Well Test Engineer
Specific responsibilities include

- Supervise transport, loading and handling of tubulars and running equipment.
- Supervise slinging, handling, running and retrieval of tubulars.
- Maintain an independent check of the running tally during installation and retrieval of the test string.

2.9. Subsea Services Supervisor

Reports directly to the Well Test Engineer
Specific responsibilities include

- Ensure the readiness and completeness of subsea equipment in support of the Well Test Operation
- Verify interfaces between the subsea equipment and the BOP, including spaceout calculations and drawings

- Supervise the installation and operation of subsea equipment
- Provide support to the Well Test Engineer in planning and scheduling to ensure interfaces between operations are seamless
- Operate subsea equipment in an emergency

2.10. Downhole Tools (DST) Services Supervisor

Reports directly to the Well Test Engineer

Specific responsibilities include

- Ensure the readiness and completeness of downhole tools in support of the Well Test Operation
- Supervise the installation and operation of test tools
- Provide support to the Well Test Engineer in planning and scheduling to ensure interfaces between operations are seamless
- Supervise the operation of downhole tools in an emergency

2.11. Wireline Services Supervisor

Reports directly to the Drilling Supervisor

Specific responsibilities include

- Ensure the readiness and completeness of wireline equipment in support of the Well Test Operation
- Review wireline operations required for the well test
- Supervise the installation of pressure control equipment and wireline operations
- Advise the Well Test Engineer in relation to the interpretation of logs e. g. for depth correlation
- In the event of an emergency alarm during electric line operations, stop the wireline winch immediately and apply the brake and proceed to the assigned muster station

2.12. Slickline Services Supervisor

Reports directly to the Well Test Engineer

Specific responsibilities include

- Ensure the readiness and completeness of slickline equipment in support of the Well Test Operation
- Supervise the installation of pressure control equipment and slickline operations
- Provide support to the Well Test Engineer in planning and scheduling to ensure interfaces between operations are seamless

- In the event of an emergency alarm during slickline operations, stop the slickline winch immediately and apply the brake and proceed to the assigned muster station

2.13. Mud Engineer

Reports directly to the Drilling Supervisor

Specific responsibilities include

- Supervise well clean out operations
- Monitor condition and weight of fluids including drilling fluids and brine.
- Monitor pit volumes during operations.
- Inspect pits prior to filling to ensure cleanliness standard.
- Analyse fluid samples in support of the Well Test Operation

Appendix 7: Wellsite Well Test Equipment Preparation Checklist

Resource Company Name
Field Name
Well Name
Document Number
Revision Number

Review & Approval

Name	Position	Signature	Date
Author	Well Test Engineer		
Review	Drilling Supervisor		
Approval	Drilling Department Manager		

Distribution

Name	Position	Type	Hard Copies Qty
Name 1	Drilling Department Manager	Hard & Soft	1 copy
Name 3	Well Test Engineer	Hard & Soft	1 copy
Name 4	Offshore Drilling Supervisor	Soft	
File	Document Control	Soft	

1.0. OVERVIEW

1.1. Purpose

This document provides a tool for use by the Well Test Engineer at the Wellsite to ensure that Well Test Equipment Preparations are in accordance with planning and with the appropriate standards.

1.2. Checklist Instructions

- This checklist must be completed by the Well Test Engineer before production operations commence
- Mark as N/A any item not relevant to the well test operation
- On completion, this documents must be signed and retained on file through document control

1.3. General Information

1. Well Name
2. Facility Name
3. Date of Inspection

2.0. EQUIPMENT PREPARATION CHECKLISTS

2.1. Documentation

- Well Test Design Report available at the facility for reference
- Equipment certification available at the facility for reference
- Certification file has been checked against the physical equipment to confirm validity
- Programs and references have been distributed
- Contingency plans, technical information, special procedures are available for reference

2.2. Layout & Installation

- Equipment has been laid out in accordance with the layout diagram
- Sample points, flanges, pipe connections and valves located at least 3 m from air intakes and non hazardous rated electrical sources
- Intake fans or electrical points that fall within the hazardous area of the test equipment are disconnected and tagged out or are hazardous areas certified
- Equipment been rigged up in accordance with the approved P & ID
- Pressure relieving device settings are as per P & ID
- Hi-Lo pressure switches are as per P & ID
- Rupture discs are as per P & ID
- Production lines secured with clamps and tie down wire as required
- Vessel relief and vent lines are piped overboard and secured
- Well test equipment vents must not share rig vent lines unless the rig system is isolated using a spade, blind flange or equivalent
- Test equipment properly earthed, either welded or earth strap.
- Separator vessel and flowlines, including the gas lines have been drained of water after pressure testing
- Meter factors have been performed on the liquid meters
- Differential has been calibrated and the calibration chart provided to the Well Test Engineer
- If the well test anticipates H2S during production, confirm flow wetted surfaces are NACE service.
- Flashing beacons if required in the risk assessments have been installed
- Propane bottles positioned to shield from heat radiation.

2.3. Fire & Escape

- A well test specific fire drill has been completed just prior to well test operations
- Well Test Engineer has briefed fire teams on specific hazards
- Fire team muster and location of fire fighting equipment agreed with fire teams and approved by the OIM
- Deluge, fire monitors and other emergency equipment in the test area are operational and have been tested
- Primary and secondary escape routes available as indicated on the Fire & Escape Plan
- Escape routes free from obstructions
- No dead legs greater than 7 m
- Walkways and steps provided over pipework to facilitate access and minimise trip hazards
- Adequate lighting available for 24 hour operations

2.4. Air Compressors

- Compressor shutdown switch accessible and clearly labelled
- Air compressors located on deck as per the layout diagram
- Air hoses laid out to minimise trip hazards free from kinks
- Air hose end fittings attached using appropriate hose clamps
- Connections secured with whip checks and tied down
- Air compressors have been function tested to both booms
- Compressors within the range of a dedicated diesel fill hose fitted with a bowser or shut off valve
- Dead head pressure of diesel supply pump will not exceed fill hose rating

2.5. Methanol

- Methanol shipped and stored appropriate chemical transportation tanks
- Methanol tanks clearly labelled and accompanied by MSDS.
- Salt positioned around tank to aid fire visibility
- Methanol delivery lines including the subsea umbilical flushed prior to operations
- Methanol fire fighting chemicals and equipment deployed in proximity to methanol tanks

2.6. Emergency Shutdown System

- ESD installed, function tested and operation witnessed by the Well Test Engineer
- Pilot air hoses positioned clear of potential hot spots and hose pinch points
- Pilot system left energised for 24 hour test
- ESD stations located as per the Fire & Escape plan
- Pilot lines fitted with pneumatic quick dumps & non return valves to accelerate operation
- Hydraulic lines fitted with quick dumps to accelerate operation

2.7. Steam

- Steam boiler located on deck according to the layout diagram
- Steam rated hose installed to deliver steam to and from the heat exchanger
- Steam lines have been laid so as to avoid "where possible" crossing walkways or wherepersonnel are likely to be present during operations
- All hoses have identity tags with identification and inspection information
- Hoses visually in good condition with no cracks, rips, kinks or loose fittings
- Boiler is connected to the ESD system
- Boiler diesel tank is in range of a dedicated diesel hose fitted with a bowser or shut off valve
- Dead head pressure of diesel supply pump will not exceed fill hose rating

2.8. Hydrogen Sulphide

- Resource Company Hydrogen Sulphide H2S plan available for reference
- Personnel trained in H2S operations
- H2S detection equipment on hand
- BA sets on hand
- Personnel designated to work with BA sets clean shaven
- Safe briefing areas defined and crews briefed on location and alarms
- Minimum wind speed established for flaring.
- Radio operator and well test crew briefed to inform driller of change in conditions
- Wind direction indicators visible around deck.
- Test area and outside restrictions in place as required by the H2S plan
- Deck hatches and doors secured

2.9. Flaring

- Pilots function tested on both sides
- Heat shields installed
- Water cooling system installed and tested
- LPG tanks shielded from heat radiation

3.0. PRE-TEST SAFETY BRIEFING CHECKLISTS

3.1. Crew Safety Briefing

- Permit to Work in place
- Other hot work permits suspended
- Restricted access to well test area
- Brief crews on flow and shut in schedule
- Review type and sequence of fluid recovered; eg diesel followed by brine followed by hydrocarbons.
- Flare will be intermittent.
- Wind direction and boom selection for flaring
- Noise hazards and hearing protection
- Heat radiation hazards
- Brief crews on the likelihood of H2S production and on H2S hazards
- Hazards associated with Hydrates, refer to snow on pipe and the purpose of methanol
- Methanol hazards: Invisible: Salt Bund: Special fire fighting chemical
- Assume all well test pipework pressurised
- No crane lifts over well test equipment
- No crane lifts over umbilicals, control panels
- No crane lifts over compressors or boiler

- Identify driller as principal focal point for communications
- Identify methods of communications phone and radio's
- Driller will make PA announcement and advise control room to notify boats of flaring operations
- Driller will ensure that kill weight fluid is to hand at all times (Minimum 1 tubing volume) lined up ready to pump
- Discuss monitoring of annulus pressure
- Discuss radio etiquette: No unnecessary traffic, acknowledge signals use patience when having to repeat instructions: If in doubt check in person.
- Dedicated fire watch duties during well testing
- Well test supervisor to brief fire watch personnel regarding specific duties.
- Surface temperatures monitored with a laser thermometer throughout flow periods.
- Personnel monitoring compressor and boiler diesel levels
- Review what happens when the ESD is operated
- Review locations of ESD stations: Well Test Supervisor to brief rig crew on locations of ESD stations.
- Review who is expected to operate an ESD and under what circumstances

3.2. Well Test – Emergency Response

- Activate ESD
- Close Choke Manifold
- Stop tank transfer operations
- Shutdown Boiler
- Shutdown Compressors
- Proceed to Muster Station

3.3. Final Checks

- Notifications have been sent to the regulator
- Surface equipment has been pressure tested in accordance with an approved pressure test procedure
- Signed and labelled pressure test chart retained for records
- Lines have been walked by rig management and initial valve configuration checked
- Final confirmation of wind direction

Well Test Operations will not commence until all preparations have been completed!

Checklist Completion Sign Off

Well Test Engineer

Glossary

Accumulator system A small reservoir of stored energy, usually compressed nitrogen, designed to boost hydraulic pressure signals between surface and subsea equipment in deepwater applications to ensure rapid valve operation times.

AFE Authorization for expenditure.

ALARP As low as reasonably practicable.

API grade A numeric standard for crude oil density published by the American Petroleum Institute.

Bails Arms attached to the top drive, one on either side, from which hang the elevators used to engage drilling pipe or well test tubing. They allow flexibility while the elevators pick up pipework and tubing—also known as Bail Arms or Elevator Links.

Barrier Any physical means for containing reservoir pressure. Well testing barriers may differ from those used during drilling, both in quantity and in design.

Barrier philosophy The policy in respect of well barriers to protect the facility from reservoir pressure; they may differ from company to company.

Basis for Design A document containing well-specific information and company objectives, providing a conceptual basis for starting the detailed design.

Best practice An industry or company standard.

BHP Bottomhole pressure. Pressure at the bottom of the well or in the reservoir.

BHT Bottomhole temperature. Temperature at the bottom of the well or in the reservoir.

Blocks Term used to describe the top drive, elevators, bails & lifting gear as an assembly.

BOP Blowout preventer, a device incorporating multiple closable pressure barriers which can isolate the well to contain pressure.

Bubble point The pressure at which gas begins to evolve from saturated oil.

Bullhead To pump fluid from surface into the formation, a part of the well-kill process.

Bunding Refers to an area of deck with scuppers and drains deliberately blocked to prevent oil or chemicals escaping into other areas or into the ocean in the event of a leak; it also refers to trays placed underneath smaller tanks and drums to contain leaks.

Carbon dioxide A gas often produced with reservoir fluid that can cause rapid deterioration in elastomer materials used in seals and that can interfere with gas flare stability. Typically, concentrations above 5 to 10 percent necessitate special planning.

Catwalk A long platform located on the pipe deck below the vee door entry to the drill floor. Pipe and tools are transferred from the pipe deck to the catwalk in preparation for pick up to the drill floor using air winches. Pipe and other equipment is layed down from the drill floor onto the catwalk also using air winches.

CCL Casing collar locator, a device for sensing metal mass accumulations in the test string, such as casing collars, used for measuring depth.

Cement pump A pump unit operated by third party primarily used to circulate cement and chemicals, but on a well test utilized to establish an underbalance and to pressure test and calibrate well test equipment.

CGR Condensate gas ratio, a measure of the liquid yield of condensate for a given volume of gas.

Choke The well test throttle; The fixed choke facilitates accurate measurements for the main flow period, whereas a variable choke allows for fine control at start-up.

Choke box The choke housing on a choke manifold.

Choke line A pipe conduit between the BOP and the rig which allows fluid communication between rig pump systems and the well when the BOP rams are closed.

Choke manifold A well test equipment assembly containing the choke housings and gate valves, used for controlling production from the well.

Circulation The process of pumping fluids into the well through the tubing or drillpipe and taking returns from the annulus to the rig fluids handling system.

Cleanup flow period A variable duration flow period during which reservoir fluid fills the test string and displaces underbalance and drilling fluids from the wellbore.

Code A standard compliance with which is mandated by law.

Coil tubing An oilfield service utlising a continuous coil of tubing ranging in size between 1.25" & 2.25", performs a wide variety of operations, including gas lifting, acid washing, wireline logging and mechanical tool functions. Effective in horizontal and vertical wells.

Contingency Alternative plan in the event a primary plan fails during execution.

Continuous Improvement A beneficial change to a standard.

Contractor Refers to an individual or a company providing an oilfield service.

Critical path The primary activity occupying a drilling rig at any given time; the critical path activities specific to a well test are generally the installation of the test string in the well, production activity, and removal of the test string from the well. These account for the greatest part of the cost associated with the well test since they occupy the drilling rig facility, land based or offshore.

Crossover A device used to interconnect between two incompatible connections of pipe or tubing.

Crown block A series of sheaves located at the top of the derrick, through which wire rope is threaded from the draw works and attached to corresponding sheaves in the travelling blocks. These provide the mechanical advantage that facilitate lifting significant loads into and out of the well.

Cushion fluid Same as underbalance fluid.

Darcy flow Relates to the way in which fluid flows through a porous medium; the flow is said to be Darcy Flow if it is laminar and Non-Darcy if turbulent.

Datum A depth reference-for example, the top of the 18 ¾-in. wellhead housing.

Demobilization The logistics effort of returning contractor equipment from a well site to a contract defined point of origin in order to go off contract or for maintenance in preparation for a subsequent operation.

Depth reference A point of elevation in a well from which all other depths are referenced; common references include Rotary Table RT, Lowest Astronomical Tide (LAT), and Mean Sea Level (MSL).

Detailed design The output of the planning process, which includes the engineering, procedures, and processes that govern the conduct of the well test.

Detonating cord Explosive material in the shape of an electrical cord, which transmits a triggering detonation to multiple charges in a gun system.

Detonator See Percussion detonator.

Development department Department responsible for planning field development, how many wells to drill, how to transport the product from the well site, for example, pipeline, floating production storage offloading vessel (FPSO), or platform; also how to process the product onshore—refine or export for sale.

Diverter A device installed just below the rotary table on a drilling rig, which serves to divert unexpected pressure in the riser to a separate vent in order to protect personnel on the drill floor.

Documents Records relating to well test planning, divided into uncontrolled and controlled documents. Uncontrolled documents provide information not intended for reference by an extended group of individuals. Controlled documents contain controlled information for the benefit of an extended group of individuals; they take various forms, for example, certificates and calibrations, procedures and records, engineering specifications, operational procedures and contracts. Document control procedures manage filing and subsequent edits, if any.

Drainage area Well test measurements from electronic gauges located near the reservoir during pressure buildup, together with seismic, geologic, and logging data, help build the three-dimensional model for drainage area—essentially, the reservoir thickness and boundary.

Drilling report A daily report on critical path activity at a facility.

Drive A pressure differential, directed toward the wellbore.

Drive mechanism Usually water or gas forcing hydrocarbons from the reservoir and filling the space created as a consequence of production.

Drop bar A metal bar deliberately dropped into the tubing string to trigger detonation of perforation guns on impact with a firing head.

Dry gas A gas only reservoir with no separate liquid phase.

DST Drill stem tests originally referred to a well test performed through a drill string; nowadays used as another term for well test.

Employee participation A concept necessary for effective work safety and compliance; essentially employee feedback on operations and safety using a designated reporting system.

Environment In a well test the conditions, natural or synthetic, that define its unique engineering challenges.

EZ valve An additional safety valve installed inside the BOP on jack-up facilities.

Final flow The last in a sequence of production periods during a well test.

Fingers A racking system located part way up the derrick, usually ~25 m on an offshore rig, to facilitate vertical storage for drill pipe stands.

Fit for purpose Conforming to design standards, performing reliably at the outset, free from errors.

Flare boom A structure extending from the side of a facility to permit flaring of hydrocarbons to take place remote from the facility.

Flare pit A pit dug into the earth into which a land-based burner head burns the hydrocarbon products of a well test.

Flaring A method for the disposal of well-test hydrocarbons, which involves the efficient combustion of hydrocarbon products from a well to atmosphere

Flow assurance The planning input to the well test design to maximize the likelihood that reservoir hydrocarbons will flow to surface. Includes perforation, tubing, and underbalance design.

Flow period A period during which the well produces well fluids to the test equipment.

Flow rate The volume of fluid produced from the well in any unit of time; gas and liquid phases are usually measured separately.

Flow sequence The order in which the different flow periods at different rates occur.

Flowhead A valve manifold situated at the top of the test tubing which directs well fluids to the well test equipment, or directs kill and underbalance fluid into the well. The flowhead also facilitates the introduction of wireline tools through a swab valve.

Fluid loss During the drilling process, the well may pass through areas where drilling fluids in the wellbore flow into the formation rock. Apart from the cost, such loss can cause a drilling hazard, since this fluid serves a well control purpose. During well tests, fluid loss may cause production problems owing to a capillary effect as it enters the rock pores, which counteracts hydrocarbon flow into the wellbore.

Foam The formation of small gas bubbles within a liquid hydrocarbon phase, which results in a large increase in volume and causes a number of handling difficulties in well test equipment.

Formation A rock stratum with a characteristic lithology, usually sandstone or limestone, that contains hydrocarbons inside impermeable boundary layers, while its porosity and permeability make it possible for hydrocarbons to flow through the stratum itself.

Formation volume factor The ratio representing the reduction in oil or gas volume at reservoir conditions to volumes at standard conditions.

Gamma ray tool A device designed to measure natural background radiation in a well. A gamma ray log is used to establish a depth reference since the profile at any given depth is unique.

Gas blow by An undesirable condition whereby gas phase fluids produce through line or equipment not designed to handle them. This may occur in a separator vessel if the liquid level drops to a point where gas starts flowing through a liquid phase outlet.

Gas cap Unsaturated gas exists as a separate phase, in a gas cap above the oil when both occupy pore space in a permeable reservoir rock.

Gate valve A particular design of high-pressure valve, which works by sliding a solid steel gate between two seats to open and close. Common in high-pressure well test equipment, flowhead, choke manifold, and steam exchanger

General test pressure A designated test pressure for all high-pressure tests, typically 20 percent higher than shut-in tubing head pressure (SITHP).

GOC Gas-oil-contact, a depth marking a transition between gas and liquid oil phase in a formation.

GOR Gas oil ratio, The ratio of gas to oil volume given as MMSCF/BBL, or million standard cubic feet gas per barrel oil; it has a significant impact on surface facility design, which must handle both phases.

GWC Gas-water-contact, a depth marking a transition between gas and water phases in a formation.

Hazard Any task or activity that, under certain conditions, could have adverse HSE consequences.

HAZID Hazard identification, a formal process for the assessment of an operation to identify hazards and assess risk.

HAZOP Hazard and Operability, a formal process for the assessment of a production process system to identify inherent design weaknesses and appropriate system safeguards.

Heat shield A physical barrier placed between a heat source and equipment or personnel to provide protection against heat radiation.

High flow An undesirable condition in which fluid production rate exceeds that expected. This may result in overpressure downstream or equipment erosion. The cause might be a choke washout.

Hot evacuated tubing fluid A load case in which gas-filled tubing creates a high differential at the packer owing to the difference in hydrostatic pressure between the liquid fluid annulus and the gas fluid tubing.

HPHT High pressure high temperature—a well classification signifying operating temperatures and pressures that call for high specification in the detailed design.

HSE Health, safety, and environment, a combination often linked together in legislation, referring to the laws governing the health and safety of personnel in the workplace and the protection of the environment.

Hydrates Hydrocarbon ice-like solids that can form in the presence of water and under the right conditions. Can cause severe production problems if allowed to develop.

Hydrocarbon A hydrogen-carbon compound; the commercially viable fluids (gas or liquid) in the reservoir.

Hydrogen sulfide H_2S, a toxic gas often produced as a by-product of hydrocarbon gas that can cause metal corrosion by a chemical process called hydrogen embrittlement. Its high toxicity necessitates a correspondingly high degree in regulation to ensure fit-for-purpose well test designs.

Hydrostatic pressure The force exerted by a liquid's weight and calculated by multiplying the liquid height by its density. The calculation has no variable for volume, whereas reservoir pressure calculations must.

Index line Used on floating MODU facilities, a wire length attached to a fixed point on the riser below the slip joint, which when pulled in tension on the drill floor is used to mark pipe to independently establish a depth reference unaffected by metocean conditions, since the riser rests on the seabed.

Inhibitors Chemicals in a flow stream that slow down or stop the solids buildup process, which may result in plugging. Some chemical compounds will dissolve in water; others will go into solution with oil if the solids result from that phase.

Initial flow Optional short flow period used to clear the perforations, always followed by an initial shut-in period to allow an initial reservoir pressure measurement.

Installation A critical path step during which the surface test crew lower the test string with tools into the casing and down to the test depth.

Kill To equalize the pressure differential between reservoir and the wellbore, stopping flow.

Kill weight The density of fluid required to produce hydrostatic force necessary to kill the well.

Kingpost A vertical support substructure, from which, the rigging used to support the flare boom, is suspended.

Land (fully landed) Land, land off, or landed all refer to lowering an incomplete or complete workstring onto some fixed weight bearing point in the well. Inside the wellhead, the test string lands off a wear bushing.

Layout Reverse pickup, it involves removing equipment from the workstring on the drill floor and transferring it to the pipe deck or catwalk using a crane or tugger.

Learnings Taken prior to demobilization, and before the test team has dispersed; these consist in a once-off audit by the operators who implemented the plan. Their feedback ensures realistic and fair planning in the future and improved communication between services, and enables quality plan maintenance as new knowledge enters the plan scope.

Leesee An exploration and development company contracted to drill for oil in certain onshore or offshore areas.

License An exclusive contract granted by a government to an exploration and development company to drill for oil in certain onshore or offshore areas. Its main features include a drilling schedule and drilling rules.

Liner A smaller casing positioned over the reservoir formation and suspended from the lower part of a larger casing to provide wellbore stability. The liner also acts as a pressure barrier during test string installation.

Liquid blow by An undesirable condition whereby liquid phase fluids produce through line or equipment not designed to handle them. This may occur in a separator vessel if the liquid level rises to the top and starts flowing into the gas line.

Load case A scenario anticipating a worst possible case for load on a test string to input into a tubing stress analysis to verify an adequate test string design.

Logistics The effort of moving personnel and material to and from a wellsite.

LPR Lower pipe ram (of a BOP)

M&L Materials and logistics

Main flow period May consist in a single flow period or multiple flow periods at different rates in order to draw down reservoir pressure.

Man-Rider A tugger certified to lift personnel, fitted with special harnesses to work at heights in the derrick, and never used to lift equipment.

MD Measured depth, measured from the wellbore along the well to a measuring point at the surface.

Metocean conditions The various parameters that describe the weather and sea environment.

Mobilisation The movement of equipment and personnel to a wellsite in preparation for operations.

MOC Management of change a process followed by wellsite personnel in the event of an unplanned deviation from procedure.

Modeling Reservoir characterisation by computer, using input from well testing and other processes.

MODU Mobile offshore drilling unit signifies a mobile drilling facility, such as a semi-submersible, drill ship, jack-up or barge.

MPR Middle pipe ram (of a BOP).

Mud An oil- or water-based solution that provides well control, maintains borehole stability, and lifts cutting during drilling operations. Also frequently used for well control during well test operations but sometimes replaced with brine or water

Mudline The ocean floor or seabed.

Mud pumps Large-capacity positive displacement triplex pumps controlled by the driller, the rig will normally have available at least three pumps to provide ample capacity. These circulate drilling fluid to the well; on the well test, they maintain annulus pressure in the test fluid and circulate seawater to cool the flare boom.

NPT National pipe taper, thread form in common use for high- and low-pressure fittings in the oil and gas industry.

NPT Non-productive time; this is any amount of critical path time spent doing unplanned work, for example, repairing equipment after a breakdown.

Offset data Data available from previous, nearby wells, which would help in design and planning.

Overbalance For well control, the hydrostatic pressure exerted by the drill in fluid at the wellbore that exceeds the reservoir pressure typically by about 200 psi, the overbalance pressure.

Overpressure An undesirable condition in a component or system when pressure within exceeds planned pressure. Possibly caused by a blockage or an accidental valve closure in low-pressure equipment at a time when production from the high-pressure section continues to flow into the low-pressure section.

OWC Oil-water-contact, a depth marking a transition between fluid phases in a rock formation.

Packer A downhole pressure barrier, installed above the wellbore formation to close off the annular space connecting the reservoir with the surface. Once set, it extrudes a seal to isolate the lower annular space from that above, channeling reservoir fluids into the test string. Its size and type depend on the limitations imposed by the casing and liner specifications used in the well design.

Percussion detonator An explosive charge triggered by physical impact, used to initiate detonation in other explosives, for example, the shaped charges loaded inside a gun system.

Perforation gun The tool used to deliver explosives to the target perforation zone, piercing the cement liner and wellbore surface. Explosive density and specification will depend on the string design, the conditions in the string, and the reservoir engineer's requirements.

Perforation interval A zone within the formation interval, which, once perforated, will yield a maximum expected flow rate—determined by reservoir engineering and geology departments.

Perforation The operation to establish reservoir communication using explosives.

Permeability The fluid flow rate through formation rock. Effective permeability takes into account the effect from mixing with other fluids and also non-reservoir rock properties such as the skin effect; a quantity determined from well test production and pressure data.

Pick-up A term that frequently occurs in procedures; it involves taking equipment from the pipe deck or catwalk using the crane or tugger, and transferring it to the drill floor for installation onto the workstring to run into the well.

Pip tag A radioactive source located inside tubing, casing, or tools that enables accurate depth determination.

POOH Pull-out-of-hole. The operation to retrieve a workstring or wire conveyed assembly out of the well. Sometimes shortened to POH.

Porosity The ratio representing free space to reservoir rock volume expressed as a percentage, used in calculations to determine the overall hydrocarbon reserves and derived from core samples taken prior to the test.

Pre-flow period Short flow period, typically 10 to 15 minutes in duration followed by a shut in period up to 1 hour, often proscribed in a well test to help obtain initial reservoir pressure prior to the main flow period.

Pre-Mobilization The period of well test planning prior to the movement of equipment and personnel to the well site.

Pressure test A procedure to establish the pressure integrity of a piece of equipment, assembly or process system. Steps include pumping in water under low- or high-pressure and monitoring for a given time period; the time period and pressure level will depend on regulations for approving specific field test equipment.

Primer Cord See Detonating cord.

Productivity Index PI for short—the liquid production ratio to pressure drawdown at the reservoir, a measure for well productivity, evaluated by flowing the well at surface for a sufficient period to achieve a stable bottomhole flowing pressure and recording downhole pressure data on electronic gauges positioned close to the reservoir.

Pup joint A short tubing section that provides flexibility if the tally needs some minor adjustment to get the depth correct. Pup joints have other uses as handling joints.

PVT data Pressure volume and temperature data acquired from the recombination of oil and gas samples in a laboratory to simulate downhole conditions, the data so acquired provides volumetric and bubble point information essential for reservoir modeling.

Racked Racked, racked back, and racked in the derrick refer to storing made-up pipe lengths in the vertical position inside the drilling derrick. By so doing, running and retrieving a workstring happens significantly faster, not having to pick up individual pipe joints from the deck.

Rams Blind or shear rams cut drill pipe in an emergency; pipe rams close to form a tight seal around drill pipe. The ram material consists in a synthetic rubber-like material or elastomer operated by hydraulic pressure. In both cases, rams provide capability to contain a blowout not contained by the drilling fluid, sealing the annular space around the drill pipe inside the BOP.

Rathole An additional length of wellbore drilled past the target formation to provide space to run logging tools past the formation or to drop guns.

Recommended practice A recommended standard.

Regulations Rules made by a regulating authority, interpreting and applying law so as to help companies comply with the law.

Reservoir A porous rock formation saturated with pressurized fluid and or gases. A compartmentalized reservoir is divided into discrete volumes by the presence of natural faults.

Reservoir fluid The reservoir contents including the hydrocarbons, water, and gases.

Reservoir pressure The pressure within the hydrocarbon bearing formation rock.

Reverse flow An undesirable condition that occurs when fluid flows in an unplanned or unexpected direction. For example, a seal or pipe failure at the inlet to a separator vessel or tank could result in the inventory of fluid flowing out of the inlet.

Rig time Another name for the critical path.

Rig tong A device used to apply torque to make up and brake out pipe and tools when running into or pulling out from the well. Rig tongs work in pairs and have jaws to latch onto sections in a manner similar to chain tongs or pipe wrenches. Winches on the drill floor apply torque through steel rope or chain connecting to each tong.

Rig visit A facility inspection; the well test engineer makes this inspection early in the planning to ensure lead time for engineering; may occur at a shipyard or well site.

RIH Run-in-hole. The opposite of POOH, the process of conveying a workstring or wire tools into a well.

Riser Large bore pipe connecting the wellhead to the BOP on an offshore rig, filled with kill weight fluid and open ended at the surface

Risk A consensus ranking that gives the likelihood a hazard will have damaging consequences.

Rope Socket A device secured to a wire end to attach tools for wireline work.

Rotary table (RT) Originally designed to rotate drill pipe and transmit torque to the drill bit, but still located centrally on the drill floor through which drilling and test string equipment pass during installation and retrieval. It now facilitates workstring suspension to run pipe or tool joints into hole, and it has the ability to rotate the workstring or to function as a depth reference.

Safety case An assessment covering all the environmental hazards, the interfaces with contractors, and any other circumstances potentially affecting a well test operation. In the safety case regime, a company assesses the risks associated with its operation and compiles a strategy for managing them. It must provide documentation as evidence to support its case.

Safety philosophy The policy behind HSE procedures; often seen in some form in well test objectives.

Sampling service The oilfield service responsible for taking PVT and other samples.

Sand face The wellbore surface area at reservoir depth.

SAT table An output from the HAZOP study, the safety analysis table displays, in a convenient and easy to follow format, the safety devices required to control process specific conditions in a well test operation.

Seal A pressure-tight connection. Seal activation methods vary; elastomer seals rely on system pressure, whereas metal-to-metal connections rely more on precision makeup to prepare them for exposure to system pressure. Seal performance depends on its effective temperature range and its resistance to the expected conditions. The specific materials used in the seal's manufacture determine these qualities.

Separator Heavy-duty surface equipment that provides a point for measuring the initial flow rates to calculate flow path size, GOR, and for taking PVT samples. It separates gas, oil, and water into single phases, having outlets to disposal and storage facilities as necessary.

SITHP Shut-in tubing head pressure, the maximum pressure the reservoir can generate at surface.

Skin An area of reduced permeability in the wellbore at the formation caused by drilling damage.

Skin effect A property not predicted by the Darcy flow equation; it has a significant impact on well yield. A well test measures skin effect through pressure and temperature readings in the near wellbore area under multi-flow rate conditions and during the shut-in and buildup periods.

Slugging Periodic and unpredictable production at higher than expected rates.

SMS Safety management system the various systems in place to manage safety at the wellsite.

Spaceout Setting components along the test string tubing so that each attains the required depth for testing, including, TCP guns, packer, test tools, subsea tree, and flowhead.

Specifications A list of dimensions, operating parameters or specific characteristics which describe a piece of equipment.

Spool A custom-made connection between the surface test equipment and facility supply booms; used also as spacer pipe for the test tree tools inside the BOP to allow the pipe rams to shut around it and close off the annulus.

Spotting Slang for placing equipment in specific areas of the deck or lease by crane.

SRO Surface readout the process of retrieving data from a gauge whilst it is still installed in the well. Either using a wire or wireless telemetry.

Stack The BOP stack.

Stakeholder When individuals or organizations commit themselves to, or take interest in, well test planning, execution, and outcomes, they become stakeholders, having responsibility for safety, environmental, commercial, and technical aspects. Stakeholders include the resource company, joint venture partners, regulators, contractors, and employees.

Standard practice A widely accepted procedure for performing a specific operation.

Standards A set of reference procedures for manufacturing or performing an operation.

Standpipe A pipe run vertically up the derrick about 10 to 12 m, having standard well test flange or hammer union connections at either end, to provide a means to connect the facility with the production flowhead using a flexible hose interconnection to compensate for vessel movement.

Steady state The condition signified by stable flow, a phase best suited for measuring GOR and other well parameters.

Steam exchanger A device that utilizes steam from an external source to raise well fluid temperature, or, in certain rare applications, to cool well fluids.

STOP program A safety management system originally developed by Du Pont and widely used throughout the oil and gas industry to record and collect safe and unsafe observations by the workforce.

String The well test tubing and the tools assembly in the well. Also referred to as Workstring.

Surge tank A low-pressure vertical tank sometimes used as a low-pressure separator or metering tank.

Swivel In well testing, a device fitted below the flowhead to permit tubing or workstring rotation.

Tally The running list for running a test string into the well—the tallied lengths for all the tools and tubing joints must accurately match up with the correct depth settings for the various packers, guns, and other tools run into the well on the string.

Test facility The collective name for the well test process equipment.

Test fluid Provides a pressure barrier and transmits pressure signals to test tools in the well. Brine (water and salts) has greater reliability during testing than drilling fluids, which compress under pressure.

Test pressure The specific pressure that must be applied in order to test equipment integrity.

Tester valve A valve positioned close to the reservoir, which, when closed, provides a barrier to the reservoir and also isolates the gauges recording reservoir pressure from wellbore storage effects.

THP Tubing head pressure, the measured pressure at the surface at any given instant.

Top drive A device suspended from the crown blocks, incorporating hydraulic motors to rotate the workstring, and a connection to pump fluid concurrently.

Trace analysis A chemistry test performed on well fluid samples to identify certain compounds, for example, sulfur, radon, H_2S and CO_2. Performed on site and in the lab; the information helps the development team determine the materials to use in completions and surface production facilities.

Tugger A winch for use in day-to-day operations on and around a drilling facility, usually air powered.

TVD True vertical depth gives the vertical depth of the wellbore from a fixed point on the surface for use in hydrostatic pressure calculations.

TWOP Test-the-well-on-paper—a program dry run attended by contractor companies, the rig, and the resource company—preferably, field personnel rather than management, to identify any inherent shortcomings and correct them before final issue. It also serves to communicate task undertakings to the field personnel responsible.

Underbalance An induced pressure differential whereby reservoir pressure exceeds that of the hydrostatic pressure exerted by wellbore fluids.

Underbalance fluid The fluid utilised to achieve an underbalance, Seawater, freshwater, brine, drilling mud, but usually diesel or nitrogen.

Underpressure An unplanned or unexpected drop in pressure, possibly owing to a line rupture or seal failure.

UPR Upper pipe ram (of a BOP)

Vee door The access space in the derrick that facilitates the movement of equipment between the drill floor and the deck.

WAT Wax appearance temperature.

Water cut The fractional water content in the flow coming from a reservoir.

Wax Hydrocarbon crystals that form when crude oil drops below the cloud point temperature. The wax content in crude oil varies between wells and oilfields. It can create significant flow assurance problems on a well test.

Wellbore storage effect The interference to the pressure in a reservoir caused by the hydrostatic effect of the fluid column in the wellbore. The main function of the downhole tester valve is to eliminate or at least minimize this effect.

Well communication Creating a single, reservoir-well system from two separate systems (the reservoir and the well) during the perforation event. It results in an expanded wellbore radius with flow paths converging on the wellbore area.

Well control Controls to monitor and maintain safe operating conditions during drilling and well testing even as conditions change, especially after perforation has established full communication with the reservoir.

Well design Incorporates features for controlling drilling process hazards, typically the well depth and trajectory; drill bit size and depth; casing size, weight, and material; and the drilling fluid type and weight.

Well test Operations to establish flow at an oil or gas well, often for the first time, take assay samples, and make measurements.

Well test design Incorporates engineering, operational procedures, and management systems for controlling well test hazards.

Well test engineer The well test supervisor and planning focal point, responsible to the oil company for testing and test planning.

Well test objectives Measures for a successful test, broadly speaking defined as one having no safety incidents, no environmental incidents, operational success with technical objectives achieved (gauge data and samples), and finally, on time and on budget.

Well test planning The process an oil company uses to manage risk on a well test operation.

Wellhead The point from which the various casings are suspended and where the BOP sits. Often acts as a depth reference or datum point.

Wet weight The weight used during planning to ensure facility deck loads remain within design limitations under test equipment laden with liquid, such as seawater.

WHP Wellhead pressure.

Wireline Electrical conductors inside an armored cable for transmitting power to downhole tools or relaying signals to the surface.

Work string The current pipe assembly in the well, possibly the drill pipe for a drilling operation, completion tubing for a completion operation, or test tubing for a well test operation. Alternative terms for each name are the drilling string, completion string, and test string, respectively.

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